AMENDED APPLICATION FOR DEVELOPMENT

OF A CONTRACT UNDER AS 43.82

THE ALASKA STRANDED GAS DEVELOPMENT ACT

BY

BP

CONOCOPHILLIPS

EXXONMOBIL

1/20/04

Table of Contents

1. Introduction

2. Application Requirements

3. Qualified Project

4. Qualified Sponsor Group
- 4.1 Commitment to a Qualified Project
- 4.2 Ownership of Stranded Gas

5. Proposed Project Plan
- 5.1 Project Overview
- 5.2 Description of Work Accomplished
- 5.3 Project Schedule / Proposed Development Activities
- 5.4 Description of Leases and/or Properties
- 5.5 Natural Gas for Alaska In-State Use
- 5.6 Options to Mitigate the Demand for Public Services / Alaska Resourcing
- 5.7 Options for the Safe Management and Operation of the Project

Appendices
- A.1 Other Requested Information
- A.2 State of Alaska Stranded Gas Legislation
  - CS HB 393
  - CS HB 16
  - Alaska Statute 43.82
- A.3 Annual Reports for Members of Sponsor Group
- A.4 2001 MMS Report - Alaska Resource Base
- A.5 North Slope Units Map
- A.6 Description of Leases within Existing Units
- A.7 Description of Leases Outside Existing Units
- A.8 North Slope Resource Estimate

1 Introduction

This document constitutes the application by a Sponsor Group, composed of BP Exploration (Alaska) Inc. ("BP"), ConocoPhillips Alaska, Inc. ("ConocoPhillips"), and ExxonMobil Alaska Production Inc., ("ExxonMobil") to develop a contract under AS 43.82, the Alaska Stranded Gas Development Act, for an Alaska Gas Pipeline Project.

The application is the initial step toward commencing the fiscal contract development process. Any draft contract that is developed to the satisfaction of the Sponsor Group and the Administration would be subject to public review and comment and then consideration by the Alaska State Legislature. If authorized by the Legislature, the contract would be passed to the Governor for execution.

The Sponsor Group expects such a contract would provide fiscal predictability and durability for the pipeline project. This fiscal predictability and durability would be beneficial to both the Sponsor Group and to the State of Alaska. The intent of this contract would be to establish simple and clear State fiscal and royalty take terms, to eliminate ambiguity and minimize project administrative costs. Furthermore, the State take terms should enhance the competitiveness of an Alaska Gas Pipeline Project to encourage this enormous, unprecedented investment. Finally, the contract must ensure that take terms would not change to the detriment of the Sponsor Group after the agreement has been signed.

BP, ConocoPhillips and ExxonMobil agree with the legislative findings and legislative intent set forth in the original Stranded Gas Development Act [1] that a stable and predictable fiscal regime for the State of Alaska is critical to support the commercial viability of the project. Further, the Sponsor Group believes that the process set forth in the Stranded Gas Development Act is a viable means to achieve that objective. Consequently, the Sponsor Group requests determination that the project is a Qualified Project and that BP, ConocoPhillips and ExxonMobil are a Qualified Sponsor Group.

AS 43.82.120 requires any applicant under the Stranded Gas Development Act to provide evidence to support that the application is for a Qualified Project (AS 43.82.100) and that the applicants are a Qualified Sponsor or Sponsor Group (AS 43.82.110). The application must also include information to support that the application is for a Qualified Project Plan (AS 43.82.130). This document is intended to satisfy these requirements and to allow the Commissioner of Revenue, with concurrence from the Commissioner of Natural Resources, to approve the application, as provided under AS 43.82.140.

It is expected that as project development activity proceeds, additional information would be available which would impact the project scope, design and timing. The Sponsor Group would expect to periodically update the project plan with new information consistent with the provisions of AS 43.82.270.

[1] SCS CSHB 393 (FIN) includes legislative findings (10) and (13), and legislative intent (b) in Appendix A.2.

Nothing in this application or any communications between the parties should be construed as a commitment by the Sponsor Group to complete fiscal contract negotiations, or to initiate engineering design, permitting, procurement, or construction of a Qualified Project or are deemed to create any obligation or liability of the Sponsor Group to proceed with a Qualified Project. In addition, any proposed fiscal contract or agreement, or further activity would be subject to review and approval by the Sponsor Group and the individual management of the members of the Sponsor Group.

The Sponsor Group believes that it will take a combination of factors for the pipeline project to become commercially viable. These factors include cost reductions, positive long-term North American natural gas market, durability and predictability of State take provisions, improved State fiscal terms, and establishment of other government frameworks.

As the commercial structure for the pipeline project becomes better defined, the Sponsor Group may wish to assign an interest in or add or withdraw a party to this application or to a subsequent fiscal contract. Such assignments may be to an affiliate of the members of the Sponsor Group or through affiliated interests in subsequently created legal entities, and would be subject to AS 43.82.260.

2 Application Requirements

AS 43.82.120 establishes the requirements for an application for development of a fiscal contract under AS 43.82.020. These requirements include:

1. That the project meets the requirements of a Qualified Project (see Section 3).

2. That the person or group submitting the application meets the requirements of a Qualified Sponsor or Qualified Sponsor Group (see Section 4).

3. That the application contains a proposed project plan, which includes the following information:

   A. A description of the work accomplished as of the date of the application to further the project (see Section 5.2).

   B. A schedule and description of proposed development activity leading to the projected commencement of commercial operations of the project (see Section 5.3).

   C. A description of each lease or property that the applicant believes to contain the stranded gas that would be developed if the project were built (see Section 5.4).

   D. A description of the methods and terms under which the applicant is prepared to make gas available to meet the reasonably foreseeable demand in this state for gas within the economic proximity of the project during the term of the proposed contract, including proposed pipeline transportation and expansion rules if pipeline transportation is part of the proposed project (see Section 5.5).

   E. A detailed description of options to mitigate the increased demand for public services and other negative effects caused by the project (see Section 5.6).

   F. A detailed description of options for the safe management and operation of the project once it is constructed (see Section 5.7).

   G. Other requested information that the Commissioner of Revenue, in consultation with the Commissioner of Natural Resources, considers necessary (see Appendix A.1).

3 Qualified Project

Following the requirements for a Qualified Project under AS 43.82.100, the Sponsor Group has listed the qualifications for the proposed project:

(1) In accordance with AS 43.82.100(1), the project principally involves the transportation of natural gas by pipeline to one or more markets.

The project, which is described in Section 5.1, would transport Alaska natural gas by pipeline to potential markets in North America.

(2) In accordance with AS 43.82.100(2), the project would produce at least 500 billion cubic feet of stranded gas within 20 years from the commencement of commercial operations.

The project would have the capacity to transport approximately four billion cubic feet of gas per day (4 Bcfd). If this capacity were achieved, the project would produce over 500 billion cubic feet of stranded gas within the first year of commercial operations, even with the expected volume ramp up.

(3) In accordance with AS 43.82.100(3), the project is capable of making gas available to meet the reasonably foreseeable demand for gas in Alaska within the economic proximity of the project.

The Sponsor Group recognizes the strong interest in making gas available for in-state use. The Sponsor Group plans to work cooperatively with potential downstream investors and the State of Alaska in a way that is consistent with the well-established regulatory framework of fair and open access. Consistent with this regulatory framework, gas can be made available for in-state use under reasonable terms and conditions. Meeting the reasonably foreseeable demand in Alaska for gas within the economic proximity of the project is addressed in this application. Section 5.5 describes the principles under which natural gas may be made available.

4 Qualified Sponsor Group

AS 43.82.110 outlines certain criteria that must be met in order for the Commissioner to determine that the applicant is a Qualified Sponsor or Sponsor Group. As detailed below, BP, ConocoPhillips and ExxonMobil believe they constitute a Qualified Sponsor Group.

4.1 Commitment to a Qualified Project – AS 43.82.110(1)

The Stranded Gas Development Act (Appendix A.2) provides three criteria measuring a Sponsor Group's commitment to a qualified project, requiring at least one of the criteria be met for the group to be considered a Qualified Sponsor Group. Specifically, the group must a) intend to own an equity interest in the project, b) intend to commit natural gas to the project or c) hold the permits required to construct and operate the project.

BP, ConocoPhillips and ExxonMobil expect as individual companies, either directly or through affiliates or through affiliated interests in subsequently created legal entities, to commit its gas to the project. As the commercial structure for the pipeline project becomes better defined, the Sponsor Group may wish to assign an interest in or add or withdraw a party to this application or to a subsequent fiscal contract. Such assignments may be to an affiliate of the members of the Sponsor Group or through affiliated interests in subsequently created legal entities, and would be subject to AS 43.82.260.

It is standard industry practice for investors in a natural gas pipeline to require firm transportation commitments from the shippers in order to justify the project investment. Each member of the Sponsor Group intends, as part of a subsequent open season process, to make such commitments of gas resource to this Qualified Project. These commitments would only be binding upon satisfaction of certain precedents.

4.2 Ownership of Stranded Gas – AS 43.82.110(2)

The Stranded Gas Development Act provides criteria measuring a Sponsor Group's gas resource access and financial strength, at least one of which must be met for the Commissioner to determine that the group qualifies as a Qualified Sponsor Group. BP, ConocoPhillips and ExxonMobil meet the natural gas resource accessibility criterion as summarized below.

As owners in both the Prudhoe Bay and Point Thomson gas resources, BP, ConocoPhillips and ExxonMobil hold a working interest in approximately 32 trillion cubic feet (TCF) of North Slope stranded gas, representing a net share of approximately 29 TCF.

To determine the Sponsor Group share of the total volume of gas to be delivered by the project, several assumptions must be made about the project. Assuming sufficient natural gas supplies are developed to fill the approximately 4 Bcfd design capacity for 35 years, approximately 50 TCF of stranded gas would be delivered to the market by the pipeline project. As such, the Sponsor Group would have interest in of over 60% of the total stranded gas assumed to be produced, well in excess of the 10% gas resource access requirement.

BP, ConocoPhillips and ExxonMobil, either directly or through affiliates, are also owners in other North Slope fields containing additional natural gas resources, including the Alpine, Endicott, Milne Point, and Northstar fields, as well as other as yet undeveloped leases. Furthermore, BP, ConocoPhillips and ExxonMobil have the potential to secure new leases and successfully discover and develop additional gas resources.

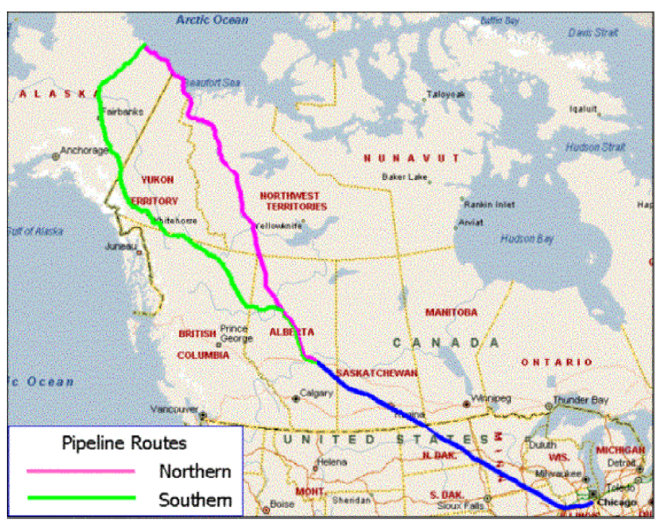
5 Proposed Project Plan

5.1 Project Overview

The Sponsor Group, either directly or through affiliates or through affiliated interests in subsequently created legal entities, has developed a preliminary plan to build a natural gas pipeline and related facilities, which would have a design capacity to transport approximately 4 Bcfd of stranded gas from the Alaska North Slope to markets in Canada and the Lower 48 States. While specific details of the project design are likely to change as additional engineering studies are conducted, the project would consist of a large diameter, large volume pipeline delivering Alaska gas to North American markets. The four major components likely forming the Alaska Gas Pipeline Project are a Gas Treatment Plant (GTP), a pipeline from Alaska to Alberta, a potential Natural Gas Liquids (NGL) Plant and a potential pipeline from Alberta to Chicago.

The GTP would be located on the North Slope and would be designed to remove carbon dioxide (CO_2), hydrogen sulfide (H_2S) and other impurities from the natural gas stream to meet inlet pipeline specifications. These pipeline specifications would also require that the gas be compressed and chilled.

The design for the pipeline from Alaska to Alberta, was developed by BP, ConocoPhillips and ExxonMobil (the "Study Group") during a 2001-02 engineering study. The pipeline design consists of 52-inch buried pipe operating at approximately 2500 pounds per square inch (psi). Compressor stations would be placed at regular intervals. In permafrost regions the gas would be chilled to manage the mechanical strains on the pipe and mitigate any potential impact on frozen soils.



The Study Group studied two of the possible routes to deliver gas from Alaska to the North American markets (see adjoining figure). Each of these routes has been determined to be technically feasible, and therefore appropriate for consideration in the Qualified Project. One route would proceed primarily east from the North Slope, under the Beaufort Sea to the Mackenzie River delta in Canada, then continuing along the Mackenzie River valley into Alberta, traversing a total of approximately 1800 miles ("Northern Route"). The other route would proceed south along the existing TAPS right-of-way before continuing east along the Alaska Highway into Alberta, traversing a total of approximately 2140 miles ("Southern Route"). Neither route was determined to be commercially viable. While it is a requirement of the Sponsor Group that the State and the Sponsor Group fully discuss all aspects of the project during the development of a fiscal contract, it is recognized that current State law prohibits the issuance of right-of-way permits for a Northern Route pipeline until a Southern Route pipeline is built.

An NGL Plant is expected to be included in the project to allow export and subsequent recovery of hydrocarbon products that are currently too light to blend with crude oil for delivery through Trans Alaska Pipeline System (TAPS). This NGL removal would likely be required in order to condition the natural gas to meet downstream market specifications. This NGL removal could be achieved through a new-build plant, through utilization of existing plant capacity or some combination thereof. While a new-build plant could theoretically be located anywhere along the pipeline route, the joint study concluded that the most likely economic locations would be in Alberta or possibly Chicago, due to the existing infrastructure and markets.

The final portion of the project involves the export of gas from Alberta. One option considered by the Study Group during the 2001-02 engineering study was a potential "new-build" pipeline system from Alberta to Chicago to provide this Alberta take-away capacity. This system would originate at the point of termination of the pipeline from Alaska to Alberta. From this location, the new line would be routed generally parallel to the existing Alliance Pipeline right-of-way, continuing 1500 miles into the Chicago gas hub. More efficient alternatives may ultimately be developed to move Alaska gas out of Alberta to consumers in Chicago or other North American markets. Alternatives include utilizing existing pipeline capacity made available by decline in existing sources, expansion of existing pipeline systems, or installation of other "new build" pipeline concepts.

5.2 Description of Work Accomplished

Alaska natural gas development projects have been proposed, planned and studied since oil and gas was first discovered in Prudhoe Bay in 1967. The options have included, among other things; various pipeline, liquefied natural gas (LNG), and gas to liquids (GTL) concepts. A natural gas pipeline is currently the most promising option.

For BP, ConocoPhillips and ExxonMobil, all of this previous work has been superseded by the most recent study that was conducted in 2001 and 2002, by the Study Group. As the major North Slope gas producers, the Study Group completed this comprehensive conceptual study to assess the feasibility of constructing a pipeline to deliver Alaska gas to Canadian and Lower 48 markets.

This study assessed the cost, technology, regulatory and environmental issues associated with the project. Approximately $125 million was spent on this study, which involved 110 owner company representatives and over one million staff-hours (including contractors). The current design basis for the Alaska Gas Pipeline Project accommodates the transportation of approximately 4 Bcfd of natural gas. The major system components considered include a Gas Treatment Plant (GTP), an Alaska to Alberta pipeline system, a potential NGL Plant, and a potential Alberta to Lower-48 pipeline system. While this study represents a significant engineering effort, design details (including export rate, pipeline size, compressor location, etc.) are likely to change as engineering progresses further.

In addition to the technical aspect of the pipeline project, the joint study team also completed an identification of significant issues that would need to be resolved to reduce project cost and schedule risks for attracting necessary capital investments. Uncertainty and lack of clarity regarding the Alaska fiscal and royalty regime were deemed as significant risks to project viability.

Following the conclusion of the 2001-02 joint study, the primary focus of Sponsor Group activity has shifted to addressing the key areas of risk identified in the study. Specific joint activities to develop the necessary government frameworks have included pursuit of U.S. Federal enabling legislation, and support of the reauthorization of the Stranded Gas Development Act in Alaska. Further joint technical work has also continued during this timeframe, including the evaluation of various cost reduction ideas including field trials of high efficiency trenching machines and evaluation of potential transportation infrastructure improvements.

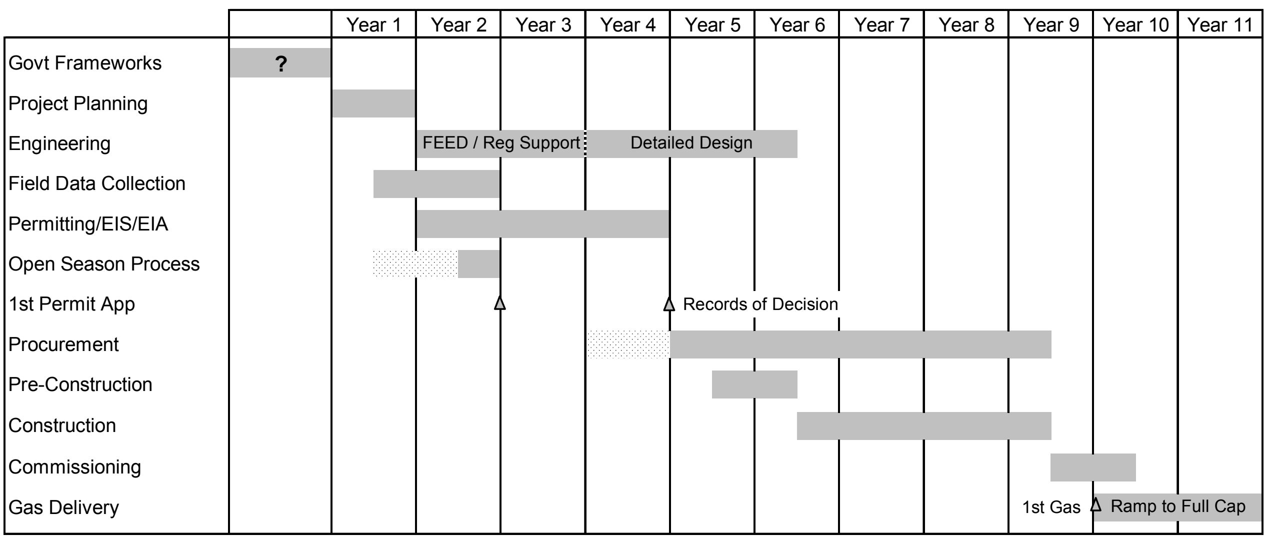
Although a pipeline is the most promising option, BP, ConocoPhillips and ExxonMobil determined that the pipeline project is not currently commercially viable for reasons noted in the Introduction. Therefore, it is appropriate to discuss potential fiscal enhancements that the State could provide. For this reason, the Sponsor Group has prepared this application to enter into discussions with the State of Alaska with the intent of achieving a predictable, durable and binding fiscal contract for the project that will contain simple and clear fiscal and royalty take terms, fiscal enhancements and contract terms that will not change over time, except in accordance with the terms of the contract.

5.3 Project Schedule / Proposed Development Activities

Figure 5.3(1) presents a conceptual timeline for planning and constructing the natural gas pipeline and related facilities. Following the establishment of suitable government frameworks (such as this Stranded Gas Development Act process), the overall timeline spans ten years, beginning with project planning, and ending with mechanical completion and commissioning. The schedule assumes that project funding, which triggers the initiation of major equipment procurement and module fabrication, would be contingent on receiving key government approvals (i.e., Records of Decision).

The current project timeline assumes that each milestone will be successfully completed. However, if issues do arise, the schedule would be extended accordingly.

Figure 5.3(1) Conceptual Project Timeline



The following provides a description of each item in the timeline.

5.3.1 Establish government frameworks

Predictability in government frameworks is needed before the Project Planning phase can begin. While the Sponsor Group is actively pursuing initiatives with each government associated with the project, the time required to achieve these frameworks is not known. Specifically in the case of Alaska, the Sponsor Group is seeking a durable fiscal contract, which is the purpose of this application.

5.3.2 Project Planning

Prior to forming a Project Management Team (PMT), the Sponsor Group would:

- conduct additional technical studies to facilitate selection of a preliminary project design basis,
- update economic analyses,
- prepare work scope, staffing plan and cost for the next project phase,
- conduct contractor selection process for the next project phase, and
- establish commercial structure and tariff principles to guide project development.

5.3.3 Engineering

Once formed, the PMT would first conduct Preliminary Engineering to develop project definition to support preparation of permit applications, analysis of project economics, specification of long lead equipment and preparation of work scopes for Detailed Engineering. This phase of engineering is often referred to as Front-End Engineering Design (FEED). Following FEED, the PMT would provide technical support during the agency review of the permit application and during the Environmental Impact Statement (EIS) and Environmental Impact Assessment (EIA) processes.

After securing the major permit decisions and authorizations, Detailed Engineering would begin generating the deliverables necessary for project construction.

5.3.4 Field Data Collection

Field data would need to be collected during all four seasons of the year to support the permitting process.

5.3.5 Permitting / EIS / EIA

This project phase comprises preparation and submittal of project permit applications, along with support for the U.S. and Canadian environmental impact processes (i.e., EIS and EIA, respectively). The goal is acceptable NEPA (National Environmental Policy Act) / CEAA (Canadian Environmental Assessment Act) decisions and receipt of FERC (Federal Energy Regulatory Commission) / NEB (National Energy Board) approvals (Records of Decision).

5.3.6 Open Season Process

The open season process is an established regulatory mechanism with the purpose of allocating pipeline capacity without undue discrimination. This process has been in place in the U.S. and Canada for many years, and the Sponsor Group's open season process would conform to all applicable FERC and NEB regulations. After the process is planned, adequate notice would be given to all potential shippers. The actual open season would be of sufficient duration for shippers to make the necessary commitments to a proposed project. Additional time would be needed following the close of the open season to allow the Sponsor Group to evaluate the submissions and, if necessary, update the pipeline design to accommodate the committed gas volume. This updated design basis would support the development of the initial regulatory permits. The Sponsor Group would file the necessary certificate applications with the FERC and NEB after the close of the open season and the updating of the project accordingly.

5.3.7 Procurement

The PMT would coordinate bidding and purchasing of materials and services for this project. Early procurement would focus on long lead materials and construction equipment to ensure timely project execution. Significant financial commitments would not be made until after the major permit decisions and authorizations, including the certificates from FERC and NEB, have been secured.

5.3.8 Pre-Construction

Prior to arrival of pipe and the pipe-laying crews, extensive preparatory work would be required. For example, pipeline right-of-way and construction easements would be cleared, compressor sites and staging areas prepared, and roads and bridges expanded and upgraded where necessary.

5.3.9 Construction

This phase of project execution would be dependent on seasonal conditions and availability of skilled resources. Project construction would cover the Gas Treatment Plant, Pipeline, Compressor Stations, and potentially an NGL Plant with activities beginning with fabrication of equipment modules and stringing of pipe, and ending with final connections and functional checkouts leading to project commissioning.

5.3.10 Commissioning / Gas Delivery

During this project phase, the PMT would work closely with operations personnel to prepare the equipment and facilities for actual operation and eventual delivery of first gas with subsequent ramp-up to full capacity.

5.4 Description of Leases and/or Properties

The project plan assumes the Alaska Gas Pipeline Project would be underpinned by gas supplied from leases within Prudhoe Bay Unit (PBU) and Point Thomson Unit (PTU). Both of these resources would be necessary to support this pipeline project. In addition to these fields, the project would also provide market access for gas from other existing resources including the Colville River Unit (Alpine), Duck Island Unit (Endicott), Milne Point Unit and Northstar Unit. Collectively, these fields could help "anchor" the development of the pipeline project.

Ultimately, it is expected that natural gas from other leases on the North Slope would be necessary to fill the pipeline for its expected life. Assuming sufficient gas supplies are developed to fill the 4 Bcfd design capacity for 35 years, approximately 50 TCF of stranded gas would be delivered to the market by the pipeline project.

As required by AS 43.82.120 (4), the Sponsor Group must provide a description of each lease or property that the applicant believes to contain stranded gas that would be developed if the project were to be built. The North Slope Units that have known quantities of gas that could be developed if the gas pipeline project were built include the Prudhoe Bay Unit, Pt. Thomson Unit, Duck Island Unit, Colville River Unit, North Star Unit, Milne Point Unit, and Kuparuk River Unit. A map providing an outline of the existing North Slope units is also provided in Appendix A.5.

To provide the necessary fiscal predictability, the Sponsor Group believes the resulting fiscal contract must apply to all Sponsor Group gas and leases, whether current or future, in a manner that provides fiscal simplicity and clarity, and is durable over the term of the contract. Appendix A.7 contains a listing of current non-unit leases in which at least one Sponsor Group member has interests.

This application only relates to the rights and obligations between the Sponsor Group and the State. The Sponsor Group acknowledges that some stranded gas is on Federal and privately owned lands. The royalty terms for those leases would not be subject to this contract.

To the best knowledge of the Sponsor Group, the lease listings in Appendix A.6 and A.7 are correct as of September 15, 2003 and reflective of those leases that our companies hold title to as of that date. Notwithstanding any errors or omissions in the listing, the intent of the Sponsor Group is that any resulting fiscal contract would apply to all Sponsor Group gas, which is delivered to the Alaska Gas Pipeline project. Moreover, unless and until provided otherwise in a contract under this application, all existing lease obligations shall continue to be governed by existing lease and unit agreements with the State.

5.4.1 Prudhoe Bay Unit

The Initial Participating Areas (IPAs) of the Prudhoe Bay Unit constitute the largest oil field in North America and the 18th largest field discovered worldwide. Of the 25 billion barrels of original oil in place, more than 13 billion barrels are expected to be recovered with current technology. More than 10 billion barrels have already been produced. The field initially contained an estimated 46 trillion cubic feet of natural gas in an overlying gas cap and from gas in solution with the oil.

Ownership in the Prudhoe Bay field includes ExxonMobil and ConocoPhillips at approximately 36% each, BP at approximately 26%, and others with an approximate combined ownership of 1%. The State of Alaska holds a 12.5% royalty interest. The PBU is operated by BP.

The total PBU gas resource that could be recovered with current technology from all PBU participating areas for delivery to a natural gas pipeline is estimated at 24 TCF[2].

5.4.2 Point Thomson Unit

The large, high-pressure PTU gas condensate field was discovered in 1977, and is estimated to contain some 8 TCF of natural gas resource, along with associated condensate. The PTU reservoir is located about 60 miles east of Prudhoe Bay. Nineteen exploration wells have been drilled around the Point Thomson area, of which 14 wells penetrated the Thomson sand. A number of 3D seismic surveys have been conducted and acquired, which cover most of the unit acreage. ExxonMobil is the PTU operator.

Given the approximately 50 trillion cubic feet of gas assumed to be delivered to the market by the pipeline project, Point Thomson gas volumes would play a key role in underpinning the commercial viability of the project.

5.4.3 Other Units with Known Gas Resource

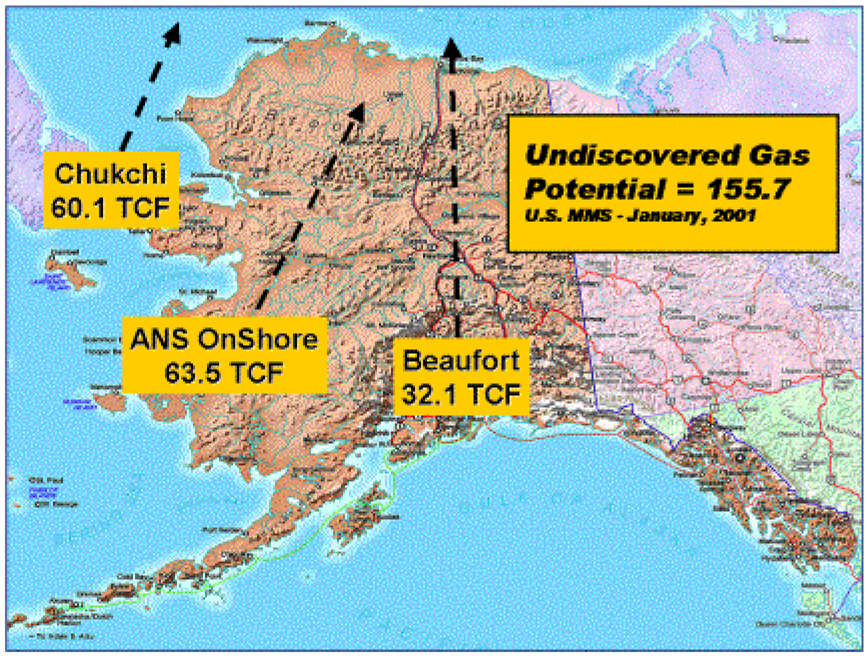
In addition to the 24 TCF of recoverable resource at Prudhoe Bay and 8 TCF of recoverable resource at Point Thomson there is also 2 TCF[3] of discovered and potentially recoverable gas resource at other North Slope fields including Alpine, Milne Point, Northstar, and Endicott.

[2] Alaska Department of Natural Resources, 2002 Annual Report
[3] Alaska Department of Natural Resources, 2002 Annual Report

5.4.4 Undiscovered Potential

Finally, exploration activity may yield additional natural gas that could be delivered by the pipeline project. Exploration volumes were a key component included in the project design work that was conducted during the producer study completed in 2002.

As outlined in Appendix A.1, the Alaska Gas Pipeline Project would be able to accommodate new discoveries during the initial open season, through potential future expansions or with capacity made available when the anchor fields go on decline.



In a January 2001 study, the Minerals Management Service (MMS) indicated that the undiscovered conventional natural gas resources in Arctic Alaska could be as high as 156 TCF of gas. The breakdown of this gas was 64 TCF from Northern Alaska, 32 TCF from the Beaufort Shelf, and 60 TCF from the Chukchi Shelf (see Appendix A.4).

In addition to conventional gas resources, the North Slope is known to contain significant accumulations of non-conventional natural gas resources, including both coal bed methane and gas hydrates.

5.5 Natural Gas for Alaska In-State Use

5.5.1 Overview

The Sponsor Group recognizes the importance of gas access for in-state use and consumption. Therefore, consistent with the guidelines provided in the Stranded Gas Development Act, the Sponsor Group plans to work cooperatively with potential downstream investors (e.g., local distribution companies, industrial users, marketers, utilities, etc.) and the State of Alaska in a way that is consistent with the well-established regulatory framework of fair and open access. This should put these prospective customers and the State in position to satisfy reasonably foreseeable local gas demand within economic proximity of the pipeline project.

The following is a discussion of the principles under which natural gas may be made available:

5.5.2 Connection Point

The Sponsor Group would work with potential downstream investors and the State to identify pipeline connection locations along the pipeline that correspond with reasonably foreseeable in-state demand that is within economic proximity of the pipeline. The Sponsor Group anticipates including one or more connection points along the main pipeline to accommodate in-state use by other separate commercial ventures. Appropriate standards, procedures and commercial terms for effecting such connections would be set under applicable regulatory frameworks.

Potential downstream investors of natural gas from the Alaska Gas Pipeline Project have the opportunity to negotiate gas purchase contracts and contract for associated pipeline capacity. Downstream investors would have the responsibility for downstream gas conditioning and distribution infrastructure.

5.5.3 Gas Purchase Contract

Potential downstream investors would have an opportunity to negotiate gas purchase contracts with any party holding title to gas, i.e., individual producer, marketer, or local distribution company, or with the State of Alaska.

At the current pipeline design rate of approximately 4 Bcf/day, State royalty volumes could be approximately 500 million cubic feet per day (MMcf/day), which is greater than the current volume consumed in the State. The Sponsor Group acknowledges that the State may choose to take some or all of that gas to help meet the demand of future markets in Alaska. The State could negotiate sales contracts directly with in-state gas users and arrange for the necessary transportation service consistent with the established regulatory process.

As mentioned before, this does not foreclose the possibility that creditworthy third parties could negotiate a gas purchase contract with any party holding title to gas. The Sponsor Group is prohibited by law from jointly marketing gas.

5.5.4 Pipeline Capacity

Potential downstream investors meeting objective creditworthiness standards would have the opportunity to contract for pipeline capacity on the Alaska Gas Pipeline Project. The allocation of capacity on interstate pipelines is governed by the regulations and policies of the FERC, promulgated pursuant to the Natural Gas Act. This FERC jurisdiction encompasses the allocation of capacity to in-state delivery points along the main pipeline.

The typical vehicle for identifying potential shippers is the initial project open season, which is conducted prior to finalizing project design and the submission of permit applications. This process allows for the allocation of pipeline capacity on a fair and equitable basis as regulated by the FERC. All terms and conditions of service, including access and the rates are subject to FERC approval with an opportunity to intervene and protest by all interested parties. The process provides a potential shipper with the ability to secure capacity via a long-term contract for natural gas shipment to its local gas conditioning and distribution infrastructure and ultimate sale to end-users. A similar open season process would be used to identify potential shippers and allocate capacity for any subsequent pipeline expansions. In addition, potential shippers would have the opportunity, subject to FERC regulations, to contract for unused capacity that shippers may release into the secondary market.

5.5.5 Local Gas Conditioning and Distribution Infrastructure

In addition to a natural gas purchase contract and a contract for pipeline capacity, a potential downstream investor would need the means to take the gas from the pipeline, condition it for local gas consumption and deliver it to the ultimate consumer. Under the current design, the pipeline would operate at approximately 2500 psi, so the pressure would need to be reduced to a level consistent with the design of the local gas distribution infrastructure and the needs of the customer. In addition, the gas would likely have a high BTU content, so facilities to control the calorific value (i.e., BTU/cf) of the gas would likely be required. Finally, local gas distribution systems would need to be installed to deliver the natural gas to the end users.

The investments in local gas conditioning and distribution infrastructure would be separate and apart from the Alaska Gas Pipeline Project and would be driven by local market economic factors. The Sponsor Group has no current plans or intent to build or own local gas conditioning and distribution infrastructure (e.g., pressure reduction equipment, calorific control equipment, spur lines, local gas distribution systems, etc.) that may be required to serve in-state demand. Subsequent downstream gas conditioning and distribution infrastructure would be the responsibility of downstream investors. It is expected that these downstream investors, either existing gas distribution companies or other entities, would pursue these opportunities.

Investment decisions for local gas conditioning and distribution infrastructure, as is the case across North America, would be driven by the size of the potential market, by the geographic concentration of the market and by the distance of the market from the main pipeline.

As local gas conditioning and distribution infrastructure develop, it is expected that shippers on the main pipeline would actively compete to serve those markets as they do in other North American markets. Since the main pipeline would be connected with the North American grid, sellers of natural gas would be seeking the best value for their gas.

5.6 Options to Mitigate the Demand for Public Services / Alaska Resourcing

The Sponsor Group recognizes that a project of the size and scope of the pipeline project would create demand for public services in communities throughout Alaska. The Sponsor Group would work with the State to address issues related to Alaska resourcing and public services.

Options to help mitigate the impacts on affected municipalities could include periodic and informative discussions on the progress of the project by the Sponsor Group with leaders and members of communities. Additionally, the Sponsor Group could work with local universities and high schools to help anticipate the future need for a qualified workforce as the project moves towards the procurement and construction phases. Socioeconomic resources report funded by the Sponsor Group could be produced during the project permitting phase, which can help to anticipate specific community effects and needs. Federal government and charitable organizations could be encouraged to enhance programs for community support services and infrastructure.

From the industry's experience during the construction of TAPS, it is clear that adequate planning is needed to mitigate demands for public services. If significant planning is conducted, much can be done to ensure that the impacts of the development can be mitigated.

One key mitigation to project impacts would be the municipalities' share of State take. The SGDA requires the State to work with affected municipalities and ensure that each municipality receives a fair and reasonable share of payments.

The Sponsor Group also recognizes the desire to provide work opportunities for Alaskans during construction of a pipeline. A skilled local workforce and capable local businesses can help the Sponsor Group complete a successful project.

5.6.1 Alaska Resourcing

The Alaska Gas Pipeline Project, given its scope and scale, would place significant demands on worldwide resources for materials, equipment and skilled labor. A large number of construction jobs would be created by the project providing an opportunity for both skilled and unskilled labor. The availability of skilled labor from across North America is a key concern to the Sponsor Group, and the Sponsor Group would work cooperatively with the State to help establish a plan that promotes development of a skilled Alaska workforce.

Following the project planning, permitting and procurement phases, the required workforce for the construction phase of a pipeline project would be expected to increase significantly. This temporary workforce would include a large seasonal workforce who would be housed mainly in construction camps associated with the physical construction of the line and associated facilities. Additionally, workers supporting project logistics would be required on a more year-round basis during the construction phase. Materials and equipment may enter Alaska through various ports both on the

North Slope and in Southern and Southcentral Alaska and be transported by road and rail to be staged near the construction site(s).

Alaska has a number of training and development programs currently in place that facilitate the development of a skilled workforce. The Sponsor Group recognizes the benefits of these programs and would work with the State to plan further development of these and other programs that could increase the availability of skilled in-state labor. A few examples of existing programs include:

- The Alaska Process Industries Career Consortium, a 2-year process technician degree program
- Itqanaiyagvik, a vocational training partnership between industry, ASRC, Ilisagvik College and the North Slope Borough school district
- The Alaska Native Science and Engineering Program
- Sponsorship of “Choices”, “Science in a Technical World” programs at middle schools
- The ALVA program which helps prepare native high school graduates for further technical studies
- The Tanana Chiefs Conference, Youth Employment Services (“YES”) program

Programs such as these can help increase the availability of an appropriately skilled Alaska workforce.

The Sponsor Group intends to fully comply with all valid federal, state, and municipal laws relating to hiring Alaska residents and contracting with Alaska businesses to work in the State on the pipeline project. To the extent Alaskans fill jobs associated with the three-year pipeline construction phase, additional labor resources would need to enter the Alaska workforce to fill vacated positions in the base economy.

5.6.2 Community Interaction

The Sponsors understand that, if this application is approved, the Commissioner would form a municipal advisory group to provide local perspectives while specific contract terms are developed under the Stranded Gas Development Act. The Administration would work with the municipal advisory group to report on the development of contract provisions as they pertain to both revenue-affected and economically-affected municipalities[4]. This process would provide a means to discuss any potential community impacts and what options are available to address those impacts. The Sponsors would assist the State in discussions with local communities as appropriate.

Consistent with the existing Federal regulatory process, the Sponsor Group envisions conducting socioeconomic assessments and consulting native and aboriginal groups during the Preliminary Engineering or FEED phase to identify in further detail potential impacts and mitigation options. The Sponsor Group, working cooperatively with the

[4] The terms "economically-affected" and "revenue-affected" municipalities are defined in AS 43.82.900.

State, would consider the input from potentially affected communities to improve mitigation plans where feasible.

5.6.3 Public Revenues and Benefits

Previous work by the Sponsor Group indicates that the Alaska Gas Pipeline Project would generate significant tax and royalty revenues for the State of Alaska. Also, Alaska's oil and gas exploration and production industry would be strengthened with an export outlet to the Lower 48 natural gas market. Basin-opening projects like this in other parts of the world have been successful in stimulating additional exploration and development, once the initial means to transport previously stranded gas to market are established.

The Sponsors recognize that, in the course of constructing the pipeline, public services would see additional demands placed on them. Lessons learned during TAPS construction would be useful in addressing the potential community impacts of the Alaska Gas Pipeline Project.

The Sponsors believe any temporary burdens this project may place on public services would be outweighed by the public revenues and benefits that are generated.

5.7 Options for the Safe Management and Operation of the Project

Commitment to the protection of the health and safety of people, the environment, and property is a fundamental business practice for each of the members of the Sponsor Group. The safe management and operation of the pipeline project is important to the Sponsor Group. This is true during all phases of the project, including engineering and design, field studies, construction, operation and maintenance, and eventually in the decommissioning of the project.

The Sponsor Group recognizes that the public is demanding higher levels of safety from industry. A primary goal of the Sponsor Group is to provide a safe, reliable, and environmentally responsible pipeline system. Managing the integrity of the pipeline project is the key to achieving this goal.

5.7.1 Safety as a Component of Pipeline Design

The pipeline would be designed to stringent standards of safety and system integrity. The pipeline industry utilizes many principles in pipeline design development, and factors such as the following would be applied to the design of the pipeline project:

- Use of modern technology,
- Rigorous material specifications,
- Regular use of “smart pigs” to detect potential pipeline problems before they occur,
- Advanced construction methods (trenching, welding, river crossings),
- Advanced communication and control systems,
- Advanced monitoring and maintenance systems,
- Marking of pipeline location where appropriate to avoid third party damage, and
- Planning and coordination of inspection and response capabilities throughout the pipeline corridor.

The Sponsor Group would be able to use lessons learned from decades of Arctic experience and combined pipeline operations experience worldwide to reduce further the safety risks associated with this project. The pipeline is currently designed to be buried through the majority of its length. The ultimate design for the pipeline would account for the presence of permafrost and discontinuous permafrost with pipeline temperature being carefully managed. The potential for seismic activity, which necessitates designing a pipeline that can tolerate movement in three dimensions, would also be addressed.

5.7.2 U.S. Federal Government Safety Standards

Should the Alaska Gas Pipeline Project proceed, it would be designed, constructed, and operated in a way that complies with all applicable government safety standards.

The Pipeline Safety Act (49 U.S.C. 60101 et seq.) requires the Secretary of

Transportation to prescribe and enforce standards for the safe operation of interstate natural gas pipelines. The Department of Transportation (DOT) Research and Special Programs Administration (RSPA), acting through the Office of Pipeline Safety (OPS), administers the DOT national regulatory program to assure the safe transportation of natural gas. The OPS develops regulations and other approaches to risk management to assure safety in design, construction, testing, operation, maintenance, and emergency response of pipeline facilities.

The Pipeline Safety Act requires each operator to develop and maintain written procedures. These procedures must include safe practices in every circumstance of pipeline operation, including those occurring during maintenance, normal operating conditions, and abnormal operating conditions. In every operating scenario, the operator must provide for surveillance of the pipeline and associated facilities, as well as for emergency response capabilities. These activities must be coordinated with local public safety authorities and officials.

Each company in the Sponsor Group has an assurance process to ensure compliance with the provisions of the Pipeline Safety Act.

5.7.3 Operation System Integrity

The goal of the project would be to provide safe and reliable delivery of natural gas to customers without adverse effect on employees, contractors, the public, or the environment. Managing the integrity of a gas pipeline system is key to accomplishing this goal. Operational excellence is achieved by implementing a comprehensive system of integrity management that includes, among others, the following items:

- Security
- Right-of-Way and Control System Maintenance
- In Line Inspection of Pipe
- Pipeline Surveillance
- Pipeline Leak Detection
- Repair Procedures
- Emergency Response
- Interface with Community
- Change Management Procedures
- Documentation and Record Keeping

The details of the safety management plan for the pipeline would be tailored to the specific locations, conditions, and operations that are relevant to this particular project. The safety of people and protection of the environment would remain a primary focus.

Appendix A.1	Other Requested Information

Plans for Point Thomson

The PTU owners are considering several potential early field development scenarios to produce liquid condensate in advance of gas sales. Each of these options would preserve gas for future sale and facilitate PTU being an anchor field for the gas pipeline. Point Thomson development plans are subject to regular review by the Alaska Department of Natural Resources.

Field/Pool Rules

Following the identification of a commercially viable gas pipeline project, it is anticipated that existing field and pool rules would need to be reviewed to support major gas sales. The unit owners would directly address key issues with the State for each North Slope unit as necessary. Members of the Sponsor Group (BP, ConocoPhillips and ExxonMobil), as individual owners in major North Slope units, would actively participate with other unit owners in identifying any possible field/pool rule modifications needed.

Potential for Regulatory Difficulties

The scale of the Alaska Gas Pipeline Project, and the fact that it is an international project, offers many permitting and regulatory challenges, and thus increased investment risk. Establishing a clear, efficient and predictable regulatory framework in the U.S. and Canada is essential for the project to advance.

The Sponsor Group is encouraged by the State's recent efforts to improve regulatory efficiency in the State. While the U.S. and Canadian federal governments would have the largest roles in permitting the gas pipeline, an efficient State regulatory process is also very important. The Sponsor Group is committed to working closely with the State to identify ways to further improve the effectiveness of the State regulatory framework in support of a gas pipeline project.

Open Season Plans and Access to Pipeline

The Sponsor Group is aware that the State is promoting continued exploration in the State. The Alaska Gas Pipeline Project would encourage exploration by providing a commercial outlet for gas. Pipeline capacity could be secured in at least three ways:

- Open season process for initial installation
- Open season process for future expansion
- Unsubscribed and secondary capacity market

- Open Season Process for Initial Installation

Holders of exploration acreage could participate in the open season process for the initial capacity in the Alaska Gas Pipeline Project. The purpose of an open season would be to allocate pipeline capacity without undue discrimination. The capacity requested by a potential shipper during an open season could be based on successful discoveries to date, as well as the risked prospectivity of remaining exploration acreage. Additionally, any third party (e.g., natural gas marketing companies) that meets the requirements of any open season could also secure capacity.

The open season process has been in place in the U.S. and Canada for many years. The Sponsor Group's open season process would conform to all applicable FERC and NEB regulations.

- Open Season Process for Future Expansion

Based on exploration activity and success, as well as the performance of existing fields, sufficient prospective gas supplies may be identified to support an expansion in pipeline capacity. Options for expansion of the Alaska Gas Pipeline Project are discussed in more detail later in this Appendix.

- Unsubscribed or Secondary Capacity Market

Should potential shippers elect not to take part in the initial open season process or in a subsequent expansion open season process, it may be possible that unsubscribed pipeline capacity and/or secondary capacity could be available, particularly in the later years when the anchor fields, which include PBU and PTU, go on decline. At any time, the pipeline can offer any unsubscribed, available capacity to any interested shipper without undue discrimination. Additionally, shippers who choose not to use their contracted capacity may market the capacity to other potential shippers consistent with FERC approved tariffs, policies, and regulations.

- Common Carriage versus Contract Carriage

The basis on which gas pipeline capacity is secured is different from that of liquids pipelines. U.S. liquids pipelines that provide interstate service are regulated as "common carriers" pursuant to regulations derived from the Interstate Commerce Act. Under the common carrier regulations, shippers are not allowed to exclusively reserve contract quantities of capacity and, therefore, do not pay related monthly demand/reservation charges - payment for capacity utilization is based on actual throughput volumes. Advance commitments for oil pipeline capacity are not necessary, but a shipper is not assured of a specific level of capacity availability. When new oil supplies are tendered for transportation on a full pipeline, available capacity may be prorated or curtailed among existing shippers.

Interstate gas pipelines are regulated by FERC pursuant to the Natural Gas Act and regulations promulgated pursuant thereto. While some natural gas is used as a feedstock in other processes, most gas usage is closely related to critical end uses, like home heating and electricity generation. As required by FERC regulations, natural gas pipelines operate as open access "contract carriers", where capacity is awarded to shippers without undue discrimination. Subject to availability, capacity can be contracted on a firm basis for a specified period of time. Open seasons are often used to ensure capacity is awarded without undue discrimination to all parties that meet the open season requirements.

Pipeline owners desire these long term contracts to ensure repayment of the capital cost of building the pipeline - without them pipeline projects could not be financed. Shippers need the contract quantity commitment to ensure capacity is available to support their needs. A shipper's economics are founded in the availability of the contracted capacity. In exchange for the pipeline's commitment to reserve a specified contract quantity of capacity for a shipper, the shipper agrees to pay a monthly charge. Similarly, in Canada, NEB regulated pipelines operate as contract carriers pursuant to the National Energy Board Act.

The FERC and National Energy Board in Canada have long required that all potential shippers have a fair chance to obtain firm pipeline capacity that becomes available.

Possible Expansion Scenarios

The capacity of the Alaska Gas Pipeline Project could be increased through expansion projects. As noted previously in this Appendix, the FERC would regulate the fair and equitable allocation of this expanded capacity. Such an expansion may be accommodated through upgrading compression capacity, by installing infill compression stations or through full or partial line looping. All three techniques are commonly employed by the industry.

The Sponsor Group's study investigated in some detail the option of installing infill compression, indicating that additional capacity of approximately 1 Bcfd could be added by placing an additional compressor station between each of the initially installed stations. Additional increments could be accommodated by looping all or portions of the line, per standard industry practice. Also, smaller increments may be accommodated as well.

When evaluating the feasibility of an expansion, contractual commitments, capital costs, fuel gas usage and operating costs would be considered. The impact of these and other variables would be dependent on the targeted expansion capacity and the original design configuration.

Appendix A.2 | State of Alaska Stranded Gas Legislation

CS HB 393 - 1998 Stranded Gas Development Act

CS HB 16 - 2003 Reauthorization

Alaska Statute 43.82

SENATE CS FOR CS FOR HOUSE BILL NO. 393(FIN)

IN THE LEGISLATURE OF THE STATE OF ALASKA

TWENTIETH LEGISLATURE - SECOND SESSION

BY THE SENATE FINANCE COMMITTEE

Offered: 5/10/98
Referred: Rules

Sponsor(s): HOUSE RULES COMMITTEE BY REQUEST OF THE GOVERNOR

A BILL

FOR AN ACT ENTITLED

"An Act relating to contracts with the state establishing payments in lieu of other taxes by a qualified sponsor or qualified sponsor group for projects to develop stranded gas resources in the state; providing for the inclusion in the contracts of terms making certain adjustments regarding royalty value and the timing and notice of the state's right to take royalty in kind or in value from projects to develop stranded gas resources in the state; relating to the effect of the contracts on municipal taxation; and providing for an effective date."

BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF ALASKA:

*** Section 1.** FINDINGS. The legislature finds that

(1) a vast quantity of gas in Alaska is stranded from commercial development because of the cost associated with providing access to markets for that gas; on the North Slope alone, between the Colville and Canning Rivers, approximately 35 trillion cubic feet of discovered gas resources are stranded in this way;

(2) because of the high cost of providing access to markets for North Slope gas, exploration efforts there have historically focused on oil; if the infrastructure needed to provide market access for North Slope gas were economically available, it is possible that new gas exploration efforts would be initiated that could lead to the discovery and development of significantly greater gas resources than have been discovered so far;

(3) maintaining production operations, whether for oil, gas, or both, enhances the opportunities for oil and gas exploration and development on the North Slope;

(4) large areas of the state, encompassing a number of geologic provinces and basins, do not have oil and gas production and still remain largely unexplored for oil and gas; exploration for gas in some of these areas might be facilitated if infrastructure were economically available to provide access for the gas to markets;

(5) Alaskans may desire a portion of the gas from a transportation project for in-state uses; however, it is unlikely that markets will develop within the state that would need more than a relatively small proportion of the volume of stranded gas already discovered on the North Slope; therefore, the primary need for gas infrastructure for approximately the next decade will be to provide access to markets outside the state;

(6) currently the principal mode anticipated for stranded North Slope gas to access markets outside the state is a gas pipeline to an ice-free Alaska port where the gas would be turned into liquefied natural gas and exported using specially designed marine tankers;

(7) the size of the capital expenditure needed to get North Slope gas to market by way of a liquefied natural gas project requires long-term contracts for gas on the order of 14,000,000 metric tons a year of liquefied natural gas; to be successful, a North Slope liquefied natural gas project needs to reach this full annual volume in not more than six years from the commencement of commercial operations;

(8) for a North Slope liquefied natural gas project to become economically viable and competitive, the estimated costs of constructing such a project must be reduced significantly; reducing the financial risk associated with the project would also improve the project's chances of becoming economically viable and competitive;

(9) the state has contracted an extensive financial analysis of the commercialization of North Slope gas; this analysis, performed by a recognized expert in

petroleum economics, Dr. Pedro Van Meurs, indicates that changes in the local, state, and federal tax structure may be necessary to make commercialization of North Slope gas resources economically viable;

(10) although the state can do little now to reduce expected construction costs, the state can reduce some of the financial risk associated with a North Slope liquefied natural gas project or other stranded gas development projects by specifying with as much certainty as possible the state taxes and royalties that would apply to such a project throughout its life;

(11) the state could improve the economics and competitiveness of a stranded gas development project by adjusting the timing of the state's receipt of its share of the economic rent of the project; the present fiscal regime is front-end loaded, which means that the state and local governments take a significant part of their shares of the economic rent of a project early in the life of the project, even before the project starts to generate an income stream; the state and local governments could improve the economics of a stranded gas development project by taking more of their shares of the economic rent of a project later in the life of the project;

(12) the state's present fiscal regime, as it would apply to a stranded gas development project, is also regressive to the extent that it is insensitive to changes in the profitability of the project, so that, in times of low profitability, the state and local governments would take an excessive amount of the economic rent of the project, and, in times of high profitability, they would take an inadequate amount of the economic rent of a project; the state and local governments could improve the economics of a stranded gas development project by making the overall fiscal system less regressive and more responsive to the relative profitability of a project;

(13) establishing a fiscal regime applicable to a specific stranded gas development project under a long-term contract with the state, where payments would be made in lieu of other taxes, would

(A) enable the state to create a fiscal regime that is less front-end loaded and less regressive for a project without rewriting the tax laws for gas already being developed and produced;

(B) enable the state to customize the timing and burden of its fiscal regime to fit the economic circumstances of a particular stranded gas development project;

(C) reduce the financial risk of the project by reducing uncertainty about the fiscal terms applicable to the project;

(14) authorizing the state, through the executive branch, to develop a contract establishing the fiscal regime that would apply to a qualified stranded gas development project if it were built will result in contracts that are an exercise of the legislature's taxing power that is consistent with art. IX, sec. 1, Constitution of the State of Alaska;

(15) authorizing the state, through the executive branch, to develop a contract establishing a fiscal regime that reduces the risks and improves the economics of a stranded gas development project will result in contracts that are an exercise of the legislature's power under art. IX, sec. 4, Constitution of the State of Alaska, to create tax exemptions by general law and is consistent with the legislature's responsibility under art. VIII, sec. 2, of the Constitution of the State of Alaska, to provide for the utilization, development, and conservation of all natural resources belonging to the state for the maximum benefit of its people;

(16) stranded gas development projects are a matter of statewide interest because they are an important potential source of revenue to the state, job opportunities for the people of the state, and gas for use by communities throughout the state;

(17) to the extent permissible under the Constitution of the United States and the Constitution of the State of Alaska, the legislature intends that state residents and businesses share in and not be excluded from the opportunities stemming from the development of the state's gas resources; and

(18) good faith efforts by qualified sponsors, qualified sponsor groups, and contractors of qualified sponsors and qualified sponsor groups that enter into a contract with the state developed under this Act to undertake voluntary actions to provide employment opportunities for Alaska residents and opportunities for Alaska businesses are in the long-term interests of the state.

*** Sec. 2.** INTENT. (a) The legislature intends that contracts developed under this Act provide stable fiscal terms that encourage the development of stranded gas projects that otherwise might not be developed under the prevailing tax and royalty regime. The legislature further intends that any fiscal term agreed to in a contract developed under this Act in lieu of other taxes will fully and fairly compensate the people of the state for the severance, production, and sale of natural resources belonging to the people of the state, for the negative effects and the risks that a project may impose on the state, and for the value of the infrastructure that may be provided by the state to a project, including all the advantages of civilized society that may be provided by the state to the sponsors of a project.

(b) The legislature intends that, in order to provide the stable fiscal terms that will encourage development of stranded gas projects, any contract developed under this Act will express whether the state intends to be bound to the full extent allowed by the Constitution of the State of Alaska; however, the legislature further intends that the terms of a contract developed under this Act will not be binding on or enforceable against the state or the other parties to the contract unless the governor is authorized to execute the contract by the legislature.

(c) The legislature intends that a qualified sponsor or qualified sponsor group or a contractor of a qualified sponsor or qualified sponsor group that enters into a contract developed under this Act relating to a stranded gas project will, with respect to the project, voluntarily

(1) undertake reasonable measures to hire Alaska residents to perform work that they are qualified to perform on a competitive basis;

(2) assist Alaska residents who are capable of being qualified and who make a good faith effort to obtain the requisite training required for employment; and

(3) use reasonable efforts to contract with qualified Alaska businesses when their performance is competitive with regard to price, quality, and availability.

*** Sec. 3.** AS 43 is amended by adding a new chapter to read:

Chapter 82. Development of Alaska Stranded Gas.

Article 1. Contracts for Payments in Lieu of Other Taxes.

Sec. 43.82.010. Purpose. The purpose of this chapter is to

(1) encourage new investment to develop the state's stranded gas resources by authorizing establishment of fiscal terms related to that new investment without significantly altering tax and royalty methodologies and rates on existing oil and gas infrastructure and production;

(2) allow the fiscal terms applicable to a qualified sponsor or the

members of a qualified sponsor group, with respect to a qualified project, to be tailored to the particular economic conditions of the project and to establish those fiscal terms in advance with as much certainty as the Constitution of the State of Alaska allows; and

(3) maximize the benefit to the people of the state of the development of the state's stranded gas resources.

Sec. 43.82.020. Contracts for payments in lieu of other taxes and for royalty adjustments. The commissioner may, under this chapter, negotiate terms for inclusion in a proposed contract with a qualified sponsor or qualified sponsor group providing for

(1) periodic payment in lieu of one or more taxes that otherwise would be imposed by the state or a municipality on the qualified sponsor or members of the qualified sponsor group as a consequence of the sponsor's or group's participation in an approved qualified project under this chapter; and

(2) certain adjustments regarding royalty under AS 43.82.220.

Article 2. Qualification and Application Procedures.

Sec. 43.82.100. Qualified project. Based on information available to the commissioner, the commissioner may determine that a proposal for new investment is a qualified project under this chapter only if the project

(1) is a project for the export of liquefied natural gas;

(2) would produce at least 500,000,000,000 cubic feet of stranded gas within 20 years from the commencement of commercial operations; and

(3) is capable, subject to applicable commercial regulation and technical and economic considerations, of making gas available to meet the reasonably foreseeable demand in this state for gas within the economic proximity of the project.

Sec. 43.82.110. Qualified sponsor or qualified sponsor group. The commissioner may determine that a person or group is a qualified sponsor or qualified sponsor group if the person or a member of the group

(1) intends to own an equity interest in a qualified project, intends to commit gas that it owns to a qualified project, or holds the permits that the department determines are essential to construct and operate a qualified project; and

(2) meets one or more of the following criteria:

(A) owns a working interest in at least 10 percent of the stranded gas proposed to be developed by a qualified project;

(B) has the right to purchase at least 10 percent of the stranded gas proposed to be developed by a qualified project;

(C) has the right to acquire, control, or market at least 10 percent of the stranded gas proposed to be developed by a qualified project;

(D) has a net worth equal to at least 33 percent of the estimated cost of constructing a qualified project;

(E) has an unused line of credit equal to at least 25 percent of the estimated cost of constructing a qualified project.

Sec. 43.82.120. Applications. (a) A qualified sponsor or qualified sponsor group may submit to the department an application for development of a contract under AS 43.82.020 evidencing that the requirements of AS 43.82.100 and 43.82.110 are met. The application must be submitted in the manner and form and contain the information required by the department.

(b) Along with an application submitted under (a) of this section, an applicant shall submit a proposed project plan for a qualified project that contains the following information based on the information known to the applicant at the time of application:

(1) a description of the work accomplished as of the date of the application to further the project;

(2) a schedule of proposed development activity leading to the projected commencement of commercial operations of the project;

(3) a description of the development activity proposed to be accomplished under the proposed project plan;

(4) a description of each lease or property that the applicant believes to contain the stranded gas that would be developed if the project was built;

(5) a description of the methods and terms under which the applicant is prepared to make gas available to meet the reasonably foreseeable demand in this state for gas within the economic proximity of the project during the term of the

proposed contract, including proposed pipeline transportation and expansion rules if pipeline transportation is a part of the proposed project;

(6) a detailed description of options to mitigate the increased demand for public services and other negative effects caused by the project;

(7) a detailed description of options for the safe management and operation of the project once it is constructed;

(8) other information that the commissioner of revenue, in consultation with the commissioner of natural resources, considers necessary to make a determination that

(A) the work accomplished as of the date of application, the schedule of proposed development activity, and the development activity proposed to be accomplished under the proposed project plan reflect a proposal for diligent development on the part of the applicant;

(B) the proposed project plan does not materially conflict with the obligations of a lessee to the state under a lease or under a pool, unit, or other agreement with the state; and

(C) the proposed project plan describes satisfactory methods and terms for accommodating reasonably foreseeable demand for gas in this state within the economic proximity of the project during the term of the proposed contract.

(c) The requirements of (b) of this section do not diminish the obligations of a qualified sponsor or member of a qualified sponsor group to the state or restrict the authority of the commissioner of revenue or the commissioner of natural resources under any other law or agreement relating to a plan of development for a lease, pool, or unit.

Sec. 43.82.130. Qualified project plan. A proposed project plan submitted under AS 43.82.120 may be approved as a qualified project plan under AS 43.82.140 if the proposed project plan

(1) reflects a proposal for diligent development of the project on the part of the applicant;

(2) does not materially conflict with the obligations of a lessee to the

state under a lease or under a pool, unit, or other agreement with the state; and

(3) describes satisfactory methods and terms for making gas available to meet the reasonably foreseeable demand in this state for gas within the economic proximity of the project during the term of the proposed contract.

Sec. 43.82.140. Review of applications and determination of qualifications. (a) The commissioner shall review an application submitted under AS 43.82.120 to determine whether the provisions of AS 43.82.100 concerning a qualified project and AS 43.82.110 concerning a qualified sponsor or qualified sponsor group have been met. The commissioner may approve an application only if those provisions have been met.

(b) If the commissioner approves an application under (a) of this section, the commissioner and the commissioner of natural resources shall review the proposed project plan submitted with the application to determine whether the provisions of AS 43.82.130 have been met. The commissioner may approve the proposed project plan as a qualified project plan only if the commissioner of natural resources concurs in the approval.

(c) The commissioner shall send to the applicant written notice of and the reasons for the determinations made under (a) and (b) of this section.

Sec. 43.82.150. Actions challenging determinations on applications. (a) Only an applicant under AS 43.82.120 who is aggrieved by a determination of the commissioner of revenue or the commissioner of natural resources under AS 43.82.140 may seek judicial review of the determination.

(b) The only grounds for judicial review of a determination made under AS 43.82.140 are

(1) failure to follow the qualification and application procedures set out in AS 43.82.100 - 43.82.180; or

(2) abuse of discretion that is so capricious, arbitrary, or confiscatory as to constitute a denial of due process.

Sec. 43.82.160. Multiple applications for similar or competing qualified projects. Nothing in this chapter prohibits different qualified sponsors or different qualified sponsor groups from submitting applications under AS 43.82.120 relating to similar or competing qualified projects or prohibits the commissioner of revenue or the commissioner of natural resources from reviewing and approving applications and proposed project plans under AS 43.82.140 relating to similar or competing qualified projects.

Sec. 43.82.170. Application deadline. The commissioner of revenue or the commissioner of natural resources may not act on an application for a contract submitted under AS 43.82.120 unless the application is received by the Department of Revenue no later than June 30, 2001.

Sec. 43.82.180. Withdrawal of applications. Subject to the terms of a reimbursement agreement under AS 43.82.240 or other agreement with the Department of Revenue, the Department of Natural Resources, the commissioner of revenue, or the commissioner of natural resources affecting the withdrawal of an application, a qualified sponsor or qualified sponsor group may withdraw an application submitted under AS 43.82.120 at any time before the date that the commissioner of revenue submits a contract to the governor under AS 43.82.430 without further obligation under this chapter.

Article 3. Contract Development.

Sec. 43.82.200. Contract development. If the commissioner approves an application and proposed project plan under AS 43.82.140, the commissioner may develop a contract that may include

(1) terms concerning periodic payment in lieu of one or more taxes as provided in AS 43.82.210;

(2) terms developed under AS 43.82.220 relating to

(A) timing and notice of the state's right to take royalty in kind or in value; and

(B) royalty value;

(3) terms regarding the hiring of Alaska residents and contracting with Alaska businesses under AS 43.82.230;

(4) terms regarding periodic payment to, or an equity or other interest in a project for, municipalities under AS 43.82.500;

(5) terms regarding arbitration or alternative dispute resolution

procedures;

(6) terms and conditions for administrative termination of a contract under AS 43.82.445; and

(7) other terms or conditions that are

(A) necessary to further the purposes of this chapter; or

(B) in the best interests of the state.

Sec. 43.82.210. Contract terms relating to payment in lieu of one or more taxes. (a) If the commissioner approves an application and proposed project plan under AS 43.82.140, the commissioner may develop proposed terms for inclusion in a contract under AS 43.82.020 for periodic payment in lieu of one or more of the following taxes that otherwise would be imposed by the state or a municipality on the qualified sponsor or member of a qualified sponsor group as a consequence of participating in an approved qualified project:

(1) oil and gas production taxes and oil surcharges under AS 43.55;

(2) oil and gas exploration, production, and pipeline transportation property taxes under AS 43.56;

(3) oil and gas conservation tax under AS 43.57;

(4) Alaska net income tax under AS 43.20;

(5) municipal sales and use tax under AS 29.45.650 - 29.45.710;

(6) municipal property tax under AS 29.45.010 - 29.45.250 or 29.45.550 - 29.45.600;

(7) municipal special assessments under AS 29.46;

(8) a comparable tax or levy imposed by the state or a municipality after the effective date of this section;

(9) other state or municipal taxes or categories of taxes identified by the commissioner.

(b) If the commissioner chooses to develop proposed terms under (a) of this section, the commissioner shall, if practicable and consistent with the long-term fiscal interests of the state, develop the terms in a manner that attempts to balance the following principles:

(1) the terms should, in conjunction with other factors such as cost

reduction of the project, cost overrun risk reduction of the project, increased fiscal certainty, and successful marketing, improve the competitiveness of the approved qualified project in relation to other development efforts aimed at supplying the same market;

(2) the terms should accommodate the interests of the state, affected municipalities, and the project sponsors under a wide range of economic conditions, potential project structures, and marketing arrangements;

(3) the state's and affected municipalities' combined share of the economic rent of the approved qualified project under the contract should be relatively progressive; that is, the state's and affected municipalities' combined annual share of the economic rent of the approved qualified project generally should not increase when there are decreases in project profitability, or decrease when there are increases in project profitability;

(4) the state's and affected municipalities' combined share of the economic rent of the approved qualified project under the contract should be relatively lower in the earlier years than in the later years of the approved qualified project;

(5) the terms should allow the project sponsors to retain a share of the economic rent of the approved qualified project that is sufficient to compensate the sponsors for risks under a range of economic circumstances;

(6) the terms should provide the state and affected municipalities with a significant share of the economic rent of the approved qualified project, when discounted to present value, under favorable price and cost conditions;

(7) the method for calculating the periodic payment in lieu of certain taxes under the contract should be clear and unambiguous; and

(8) while cost calculations for the approved qualified project under the contract should be based on amounts that closely approximate actual costs, agreed-upon formulas reflecting reasonable economic assumptions should be used if possible to promote administrative certainty and efficiency.

(c) Except as provided in (b) of this section, the commissioner's discretion under this section in developing proposed terms for a contract under AS 43.82.020 is not limited to consideration of the economic rent of the approved qualified project.

Sec. 43.82.220. Contract terms relating to royalty. (a) Notwithstanding any contrary provisions of AS 38, the commissioner of natural resources, with the concurrence of the commissioner of revenue and the affected parties holding a state lease or unit agreement, may develop proposed terms for inclusion in a contract under AS 43.82.020 that modify the timing and notice provisions of the applicable oil and gas leases and unit agreements pertaining to the state's rights to receive its royalty on gas in kind or in value if

(1) the viability of the approved qualified project depends on long-term gas purchase and sale agreements;

(2) certainty over time regarding the quantity of royalty gas that the state may be taking in kind is needed to secure the long-term purchase and sale agreements;

(3) the specified period of the state's commitment to take its royalty share in value or in kind does not exceed the term of the purchase and sale agreements; and

(4) the modification does not impair the ability of the approved qualified project or the state to meet the reasonably foreseeable demand in this state for gas within economic proximity of the project during the term of the contract developed under AS 43.82.020.

(b) Notwithstanding any contrary provisions of AS 38, the commissioner of natural resources, with the concurrence of the commissioner of revenue and the affected parties holding a state lease or unit agreement, may develop proposed terms for inclusion in a contract under AS 43.82.020 that establish a valuation method for the state's royalty share of the gas production from an approved qualified project.

(c) The commissioner of revenue shall include any proposed terms relating to royalty developed in accordance with this section in the proposed contract under AS 43.82.400.

(d) Nothing in this chapter permits modification of the state's rights that relate to timing, notice, and rights to receive oil royalty in kind or in value under oil and gas leases or unit agreements.

Sec. 43.82.230. Contract terms relating to hiring of Alaska residents and

contracting with Alaska businesses. (a) The commissioner shall include in a contract under AS 43.82.020 a term requiring the qualified sponsor or qualified sponsor group and contractors of the qualified sponsor or qualified sponsor group to comply with all valid federal, state, and municipal laws relating to hiring Alaska residents and contracting with Alaska businesses to work in the state on the approved qualified project and not to discriminate against Alaska residents or Alaska businesses. Within the constraints of law, the commissioner shall also include in a contract under AS 43.82.020 a term that requires the qualified sponsor or qualified sponsor group and contractors of the qualified sponsor or qualified sponsor group to employ Alaska residents and to contract with Alaska businesses to work in the state on the approved qualified project to the extent the residents and businesses are available, competitively priced, and qualified.

(b) The commissioner shall include in a contract under AS 43.82.020 a term requiring the qualified sponsor or qualified sponsor group and contractors of the qualified sponsor or qualified sponsor group to

(1) advertise for available positions in newspapers in the location where the work is to be performed and in other publications distributed throughout the state, including in rural areas; and

(2) use Alaska job service organizations located throughout the state and not just in the location where the work is to be performed in order to notify Alaskans of work opportunities on the approved qualified project.

(c) Subject to the voluntary agreement of the qualified sponsor, the commissioner may include a term in the contract providing for incentives to encourage training and hiring of Alaska residents.

(d) This section does not create or abridge individual rights and does not create a private right of action for any person.

(e) For purposes of this section,

(1) "Alaska business" means a firm or contractor that

(A) has held an Alaska business license for the preceding 12 months;

(B) maintains, and has maintained for the preceding 12 months, a place of business in the state that competently and professionally deals in supplies, services, or construction of the nature required for the approved qualified project; and

(C) is

(i) a sole proprietorship and the proprietor is an Alaska resident;

(ii) a partnership and more than 50 percent of the partnership interest is held by Alaska residents;

(iii) a limited liability company and more than 50 percent of the membership interest is held by Alaska residents;

(iv) a corporation that has been incorporated in the state or is authorized to do business in the state; or

(v) a joint venture and a majority of the venturers qualify as Alaska businesses under this paragraph;

(2) "Alaska job service organizations" means those offices maintained by the state and recommended by the Department of Labor whose functions are to aid the unemployed or underemployed in finding employment;

(3) "Alaska resident" means a natural person who

(A) receives a permanent fund dividend under AS 43.23; or

(B) is registered to vote under AS 15 and qualifies for a resident fishing, hunting, or trapping license under AS 16;

(4) "available," as applied to an Alaska resident or Alaska business, means that the resident or business is available for employment at the time required and is located anywhere in the state, not just in the area of the state where the work is to be performed;

(5) "qualified," as applied to an Alaska resident or Alaska business, means that the resident or business possesses the requisite education, training, skills, certification, or experience to perform the work necessary for a particular position or to perform a particular service.

Sec. 43.82.240. Use of an independent contractor. (a) The commissioner may use an independent contractor to assist in the evaluation of an application or in the development of contract terms under AS 43.82.200. The commissioner may condition the development of a contract under AS 43.82.020 on an agreement by the applicant to reimburse the state for the expenses of an independent contractor under this section.

(b) An independent contractor selected under this section must sign an agreement regarding confidentiality and disclosures consistent with the determinations made under AS 43.82.310 before the contractor may review information that is determined confidential under AS 43.82.310.

(c) Selection of an independent contractor under this section is not subject to AS 36.30 (State Procurement Code).

Sec. 43.82.250. Term of contract; effective date. The term of a contract developed under AS 43.82.020 may be for no longer than is necessary to develop the stranded gas that is subject to the contract; however, the term of the contract may not exceed 35 years from the commencement of commercial operations of the approved qualified project.

Sec. 43.82.260. Change of parties to an application or a contract; assignment of interests. (a) A qualified sponsor or member of a qualified sponsor group may assign an interest in or add or withdraw a party to an application under AS 43.82.120 only if the commissioner has

(1) made a finding that the assignment, addition, or withdrawal is consistent with the requirements of AS 43.82.110; and

(2) given prior written approval for the assignment, addition, or withdrawal.

(b) A contract developed under this chapter may provide for the assignment to or withdrawal of a qualified sponsor or member of a qualified sponsor group.

(c) Upon being added to an application under this section, a party becomes a qualified sponsor or a member of a qualified sponsor group, as appropriate, for the relevant project.

(d) The commissioner may not unreasonably withhold approval under (a) of this section, but may condition the approval in any way reasonably necessary to protect the fiscal interests of the state and to further the purposes of this chapter.

(e) For purposes of this section, an assignment includes a transfer of stock or a partnership interest in a manner that changes control of a qualified sponsor or member of a qualified sponsor group.

Sec. 43.82.270. Project plans and work commitments. A contract under AS 43.82.020 must include the qualified project plan approved under AS 43.82.140 and provisions for updating the plan at reasonable intervals until the commencement of commercial operations of the approved qualified project. The commissioner of revenue, in consultation with the commissioner of natural resources, may, as a term in a contract under AS 43.82.020, include work commitments or other obligations in the contract to be accomplished before the commencement of commercial operations of the approved qualified project.

Article 4. Requests for Information; Confidentiality; Disclosure of Information.

Sec. 43.82.300. Requests for information. The commissioner of revenue or the commissioner of natural resources may request from an applicant information that the respective commissioner determines is necessary to perform the respective commissioner's responsibilities under AS 43.82.140. If the application is approved under AS 43.82.140, the respective commissioner shall require the successful applicant to provide financial, technical, and market information regarding the qualified project that the respective commissioner determines is necessary for the purpose of developing contract terms for the qualified project under AS 43.82.200. If requested information is not provided, the commissioner of revenue may not continue to review the application under AS 43.82.140 or develop the contract under AS 43.82.200 - 43.82.270, as applicable.

Sec. 43.82.310. Disclosure of information; confidentiality. (a) An applicant may request confidential treatment of information that the applicant provides under AS 43.82.300 by clearly identifying the information and the reasons supporting the request for confidential treatment. The commissioner of revenue or the commissioner of natural resources, as appropriate, shall keep the information confidential until the commissioner determines whether the requirements of (b) of this section are met. If the commissioner of revenue or the commissioner of natural resources has not made a determination under (b) of this section within 14 days after receiving a request for confidential treatment, the request is considered denied. If the appropriate commissioner determines that the information does not meet the requirements of (b) of this section or if the commissioner fails to make a determination within 14 days, the commissioner shall return the information and any copies of it at the request of the applicant. If the commissioner of revenue or the commissioner of natural resources, as appropriate, returns information under this subsection, the commissioner shall cease review of the application or cease contract development under AS 43.82.200 - 43.82.270, as appropriate, unless the commissioner determines that the returned information is unnecessary to make a determination on the application or to develop contract terms under AS 43.82.200 - 43.82.270.

(b) If requested by the applicant, information provided to the commissioner of revenue or the commissioner of natural resources under AS 43.82.300 shall be kept confidential if the commissioner receiving the information determines, upon an adequate showing by the applicant, that the information

(1) is a trade secret or other proprietary research, development, or commercial information that the applicant treats as confidential;

(2) affects the applicant's competitive position; and

(3) has commercial value that may be significantly diminished by public disclosure or that public disclosure is not in the long-term fiscal interests of the state.

(c) Information determined to be confidential under (b) of this section is confidential under that subsection only so long as is necessary to protect the competitive position of the applicant, to prevent the significant diminution of the commercial value of the information, or to protect the long-term fiscal interests of the state. The commissioner of revenue or the commissioner of natural resources, as appropriate, may not release information that the commissioner has previously determined to be confidential under (b) of this section without providing the applicant notice and an opportunity to be heard.

(d) Notwithstanding the limitation in (c) of this section, the Department of Revenue and the Department of Natural Resources may provide to one another, to the

Department of Law, to the legislature, and to the Office of the Governor any information provided under AS 43.82.300 relevant to the implementation of this chapter or to the enforcement of state or federal laws. Information that is exchanged under this subsection that was determined to be confidential under (b) of this section remains confidential except as provided in (c) of this section. The portions of the records and files of the Department of Revenue, the Department of Natural Resources, the Department of Law, the legislature, and the Office of the Governor that reflect, incorporate, or analyze information that is determined to be confidential under (b) of this section are not public records except as provided in (c) of this section.

(e) Notwithstanding the limitation in (c) of this section, information that is determined to be confidential under (b) of this section shall be disclosed on request by the commissioner of revenue, the commissioner of natural resources, or the attorney general to a legislator; to the legislative auditor; and, as directed by the chair or vice-chair of the Legislative Budget and Audit Committee, to the director of legislative finance, to the permanent employees of those divisions who are responsible for evaluating a contract under AS 43.82.020, and to agents or contractors of the legislative auditor or the director of legislative finance who are engaged to evaluate a contract under AS 43.82.020. Information that is determined to be confidential under (b) of this section may also be disclosed by the commissioner of revenue or the commissioner of natural resources to an independent contractor under AS 43.82.240 or to a municipal advisory group established under AS 43.82.510. Before confidential information is disclosed under this subsection, the person receiving the information must sign an appropriate confidentiality agreement.

(f) If the commissioner of revenue chooses to develop a contract under AS 43.82.020, the portions of the records and files of the Department of Revenue, the Department of Natural Resources, the Department of Law, and a municipal advisory group established under AS 43.82.510 that reflect, incorporate, or analyze information that is relevant to the development of the position or strategy of the commissioner of revenue, the commissioner of natural resources, or the attorney general with respect to a particular provision that may be incorporated into the contract are not public records until the commissioner of revenue gives public notice under AS 43.82.410 of the commissioner's preliminary findings and determination under AS 43.82.400. Nothing in this subsection

(1) makes a record or file of the Department of Revenue, the Department of Natural Resources, or the Department of Law a public record that otherwise would not be a public record under AS 09.25.100 - 09.25.220;

(2) affects the confidentiality provisions of (a) - (e) of this section; or

(3) abridges a privilege recognized under the laws of this state, whether at common law or by statute or by court rule.

Article 5. Contract Review, Approval, and Termination.

Sec. 43.82.400. Preliminary findings and determination regarding the contract. (a) If the commissioner develops a proposed contract under AS 43.82.200 - 43.82.270, the commissioner shall

(1) make preliminary findings and a determination that the proposed contract terms are in the long-term fiscal interests of the state and further the purposes of this chapter; and

(2) prepare a proposed contract that includes those terms and shall submit the contract to the governor.

(b) To make the preliminary findings and determination required by (a)(1) of this section, the commissioner shall compare the projected public revenue anticipated from the approved qualified project with the estimated operating and capital costs of the additional state and municipal services anticipated to arise from the construction and operation of the approved qualified project. The commissioner shall address the reasonably foreseeable effects of the proposed contract on the public revenue.

(c) In conjunction with the making of preliminary findings and determination required by (a)(1) of this section, the commissioner shall describe the principal factors, including the projected price of gas, projected production rate or volume of gas, and projected recovery, development, construction, and operating costs, upon which the determination made under (a)(1) of this section is based. If the commissioner has previously submitted a proposed contract to the governor, the commissioner shall describe any material differences between the terms of the currently proposed contract and the previously proposed contract.

Sec. 43.82.410. Notice and comment regarding the contract. The commissioner shall

(1) give reasonable public notice of the preliminary findings and determination made under AS 43.82.400;

(2) make copies of the proposed contract, the commissioner's preliminary findings and determination, and, to the extent the information is not required to be kept confidential under AS 43.82.310, the supporting financial, technical, and market data, including the work papers, analyses, and recommendations of any independent contractors used under AS 43.82.240 available to the public and to

(A) the presiding officer of each house of the legislature;

(B) the chairs of the finance and resources committees of the legislature; and

(C) the chairs of the special committees on oil and gas, if any, of the legislature;

(3) offer to appear before the Legislative Budget and Audit Committee to provide the committee a review of the commissioner's preliminary findings and determination, the proposed contract, and the supporting financial, technical, and market data; if the Legislative Budget and Audit Committee accepts the commissioner's offer, the committee shall give notice of the committee's meeting to the public and all members of the legislature; if the financial, technical, and market data that is to be provided must be kept confidential under AS 43.82.310, the commissioner may not release the confidential information during a public portion of a committee meeting; and

(4) establish a period of at least 30 days for the public and members of the legislature to comment on the proposed contract and the preliminary findings and determination made under AS 43.82.400.

Sec. 43.82.420. Coordination of public and legislative review. To the extent practicable, the commissioner shall coordinate the public comment opportunity provided under AS 43.82.410(4) with a review by the Legislative Budget and Audit Committee under AS 43.82.410(3).

Sec. 43.82.430. Final findings, determination, and proposed amendments; execution of the contract. (a) Within 30 days after the close of the public comment period under AS 43.82.410(4), the commissioner of revenue shall

(1) prepare a summary of the public comments received in response to the proposed contract and the preliminary findings and determination;

(2) after consultation with the commissioner of natural resources, if appropriate, and with the pertinent municipal advisory group established under AS 43.82.510, prepare a list of proposed amendments, if any, to the proposed contract that the commissioner of revenue determines are necessary to respond to public comments;

(3) make final findings and a determination as to whether the proposed contract and any proposed amendments prepared under (2) of this subsection meet the requirements and purposes of this chapter.

(b) After considering the material described in (a) of this section and securing the agreement of the other parties to the proposed contract regarding any proposed amendments prepared under (a) of this section, if the commissioner determines that the contract is in the long-term fiscal interests of the state, the commissioner shall submit the contract to the governor.

(c) The commissioner's final findings and determination under (a) of this section are final agency decisions under this chapter.

Sec. 43.82.435. Legislative authorization. The governor may transmit a contract developed under this chapter to the legislature together with a request for authorization to execute the contract. A contract developed under this chapter is not binding upon or enforceable against the state or other parties to the contract unless the governor is authorized to execute the contract by law. The state and the other parties to the contract may execute the contract within 60 days after the effective date of the law authorizing the contract.

Sec. 43.82.440. Judicial review. A person may not bring an action challenging the constitutionality of a law authorizing a contract enacted under AS 43.82.435 or the enforceability of a contract executed under a law authorizing a contract enacted under AS 43.82.435 unless the action is commenced within 120 days after the date that the contract was executed by the state and the other parties to the contract.

Sec. 43.82.445. Administrative termination of a contract. (a) The commissioner shall include terms in a contract developed under AS 43.82.020 that provide for administrative termination of a party's rights under the procedures and conditions set out in this section if the party has

(1) ceased to meet the requirements of AS 43.82.110 as a qualified sponsor or qualified sponsor group;

(2) intentionally or fraudulently misrepresented, in whole or in part, material facts or circumstances upon which the contract was made;

(3) failed to comply with a condition or material term of the contract or a provision of this chapter; or

(4) failed to comply with the approved qualified project plan or any updated project plan.

(b) Before administrative termination of a contract under this section, the commissioner shall give notice to the parties of the commissioner's intent to terminate the contract and an opportunity to be heard. The commissioner may also provide the parties an opportunity to cure any deficiency that is the basis for the termination if the commissioner determines that curing the deficiency is appropriate under the circumstances.

(c) Notwithstanding (a) and (b) of this section, the commissioner may not administratively terminate a contract after the party has committed full project funding except as provided in (e) of this section.

(d) A party to a contract who is affected by the commissioner's action to terminate under (a) of this section may file an appeal with the superior court under the Alaska Rules of Appellate Procedure.

(e) The commissioner may provide terms and conditions in a contract developed under AS 43.82.020 upon which a party’s rights under the contract may be administratively terminated after the party commits full project funding.

Article 6. Municipal Participation.

Sec. 43.82.500. Obligation to share payments with municipalities. If the commissioner develops a contract under AS 43.82.020 that includes terms that exempt a party to the contract, and the property, gas, products, and activities associated with the approved qualified project that is subject to the contract, from a municipal tax or assessment in accordance with AS 29.45.810 or AS 29.46.010(b), or AS 43.82.200 and 43.82.210, the commissioner shall include a term in the contract that the party pay a portion of the periodic payments due under the contract to the revenue-affected municipality.

Sec. 43.82.505. Payments to economically affected municipalities. If the commissioner executes a contract under AS 43.82.020 that will produce one or more economically affected municipalities, the commissioner shall include a term in the contract that provides for a portion of the periodic payments to the economically affected municipalities under the principles in AS 43.82.520.

Sec. 43.82.510. Municipal advisory group. (a) If the commissioner approves an application and proposed project plan under AS 43.82.140 and decides to develop a contract under AS 43.82.020 and 43.82.200, the commissioner shall notify each revenue-affected municipality and economically affected municipality.

(b) The mayor of a municipality notified by the commissioner under (a) of this section may appoint one representative to a municipal advisory group in relation to the application.

(c) Each municipal advisory group serves until a final action is taken on the application for which the group was appointed.

(d) Each municipal advisory group shall elect a chair.

Sec. 43.82.520. Duties of the commissioner of revenue in relation to municipal participation. (a) The commissioner shall meet with each municipal advisory group periodically to report on the development of the contract provisions that affect the municipalities.

(b) In developing a contract under AS 43.82.200 - 43.82.270, the commissioner shall ensure that each revenue-affected municipality and economically affected municipality receives a fair and reasonable share of the payments provided under AS 43.82.210 in accordance with the following principles:

(1) the share of the payments to revenue-affected municipalities should

be given priority over payments to economically affected municipalities with due regard to the anticipated size of the tax base that the contract would exempt from municipal taxation by revenue-affected municipalities;

(2) the share of the payments to municipalities should be determined with due regard to the anticipated economic and social burdens that would be imposed on the municipality by construction and operation of the project;

(3) the respective shares of the total payments to the state and to municipalities should be fixed in a manner to ensure that their respective interests are aligned;

(4) to the extent practicable, the periodic amounts paid to each of the municipalities should be stable and predictable; and

(5) to the extent practicable, the provisions for sharing payments with municipalities should be consistent with the principles established in AS 43.82.210(b).

(c) In establishing the municipal shares under (b) of this section, the commissioner shall consult with the pertinent municipal advisory group.

Article 7. Miscellaneous Provisions.

Sec. 43.82.600. Governing law. If a provision of this chapter conflicts with another provision of state or municipal law, the provision of this chapter governs.

Sec. 43.82.610. Regulations. The commissioner of revenue, the commissioner of natural resources, and the commissioner of labor may adopt regulations to carry out their respective duties under this chapter.

Sec. 43.82.620. Procedures for collection of amounts due; security. (a) The commissioner may adopt procedures for the collection of amounts due the state under a contract developed under AS 43.82.020, including the collection of interest and penalties.

(b) The commissioner may require a party to a contract developed under AS 43.82.020 to provide security sufficient to guarantee amounts due under the contract.

Sec. 43.82.630. Reports and audits. The commissioner may require periodic reports from and may at reasonable intervals conduct audits and inspect the books of a party that has entered into a contract developed under AS 43.82.020 to ensure compliance with the provisions of this chapter and the regulations adopted under this chapter and of the terms of the contract.

Sec. 43.82.640. Annual report of the commissioner of labor. On an annual basis, the commissioner of labor shall prepare and present to the legislature a comprehensive report on each party to a contract with the state developed under AS 43.82.020, and its contractors, regarding the state residency of the employees working in this state on the approved qualified project that is subject to the contract. The commissioner of labor shall use state databases, including data from the quarterly reports by a party to the contract developed under AS 43.82.020 and its contractors for unemployment insurance purposes, to determine state residency of employees regarding compliance with AS 43.82.230.

Article 8. General Provisions.

Sec. 43.82.900. Definitions. In this chapter, unless the context requires otherwise,

(1) "affected municipality" means an economically affected municipality or a revenue-affected municipality;

(2) "commencement of commercial operations" means the start of regular deliveries of marketable products from an approved qualified project;

(3) "cubic foot of gas" means the quantity of gas contained in a volume of one cubic foot at a standard temperature of 60 degrees Fahrenheit and a standard absolute pressure of 14.65 pounds per square inch;

(4) "economically affected municipality" means a municipality the commissioner of revenue determines will be reasonably required to provide additional public services under the terms proposed in an application approved under AS 43.82.140(a); the commissioner may consider historical data from construction of the Trans Alaska Pipeline System, and information submitted by a municipality in making the determination;

(5) "economic proximity" means the distance within which a person may be willing to design, construct, and operate a gas line to provide service to a local consumer;

(6) "economic rent" means the estimated total gross revenue less

estimated total costs for a qualified project over the term of a contract under AS 43.82.020, measured in undiscounted nominal dollars; for purposes of this paragraph, total costs do not include a rate of return on capital, financing costs, or any payments to governments;

(7) "full project funding" means full approval by a party to a contract under AS 43.82.020 for the expenditure of the capital necessary for construction and operation of the approved qualified project that is subject to the contract;

(8) "gas" has the meaning given in AS 43.55.900;

(9) "group" means two or more persons;

(10) "lease or property" has the meaning given in AS 43.55.900;

(11) "periodic payment" means payment made in lieu of one or more other taxes under a contract under AS 43.82.020;

(12) "revenue-affected municipality" means a municipality that the commissioner of revenue reliably expects will be restricted from imposing a tax, or a portion of a tax, as a result of implementation of a contract developed under this chapter;

(13) "stranded gas" means gas that is not being marketed due to prevailing costs or price conditions as determined by an economic analysis by the commissioner for a particular project.

Sec. 43.82.990. Short title. This chapter may be cited as the Alaska Stranded Gas Development Act.

*** Sec. 4.** AS 29.10.200 is amended by adding new paragraphs to read:

(54) AS 29.45.810 (exemption from municipal taxation);

(55) AS 29.46.010(b) (exemption from municipal assessment).

*** Sec. 5.** AS 29.45 is amended by adding a new section to read:

Sec. 29.45.810. Exemption from municipal taxation. (a) A party to a contract approved by the legislature as a result of submission of a proposed contract developed under AS 43.82 or as a result of acts by the legislature in implementing the purposes of AS 43.82, and the property, gas, products, and activities associated with the approved qualified project that is subject to the contract, are exempt, as specified in the contract, from all taxes identified in the contract that would be levied and collected by a municipality under state law as a consequence of the participation by the party in the approved qualified project.

(b) This section applies to home rule and general law municipalities.

*** Sec. 6.** AS 29.46.010 is amended by adding a new subsection to read:

(b) Notwithstanding (a) of this section, a party to a contract approved by the legislature as a result of submission of a proposed contract developed under AS 43.82 or as a result of acts by the legislature in implementing the purposes of AS 43.82, is exempt, as specified in the contract, from assessment under this chapter against real property associated with the approved qualified project that is subject to the contract.

*** Sec. 7.** AS 36.30.850(b) is amended by adding a new paragraph to read:

(38) contracts between the commissioner of revenue and an independent contractor under AS 43.82.240.

*** Sec. 8.** AS 43.20.072 is amended by adding a new subsection to read:

(h) A taxpayer that has signed a contract approved by the legislature as a result of submission of a proposed contract developed under AS 43.82 or as a result of acts by the legislature in implementing the purposes of AS 43.82, providing for payments in lieu of the tax under this chapter and that has nexus with the state solely as the result of the taxpayer's participation in the approved qualified project that is subject to the contract or would not, but for such participation, be engaged in the production of oil or gas from a lease or property in this state or engaged in the transportation of oil or gas by pipeline in this state, is not required to file a return under this section unless required to do so by the contract.

*** Sec. 9.** AS 43.20.073 is amended by adding a new subsection to read:

(h) A corporation that has signed a contract approved by the legislature as a result of submission of a proposed contract developed under AS 43.82 or as a result of acts by the legislature in implementing the purposes of AS 43.82, providing for payments in lieu of the tax under this chapter and that has nexus with the state solely as the result of the corporation's participation in the approved qualified project that is subject to the contract is not required to file a return under this section unless required to do so by the contract.

*** Sec. 10.** SEVERABILITY. Under AS 01.10.030, if any provision of this Act, or the application of a provision of this Act to any person or circumstance, is held invalid, the remainder of this Act and the application to other persons or circumstances is not affected.

*** Sec. 11.** This Act takes effect immediately under AS 01.10.070(c).

(LIMITED RUN SHOWING ALL ADDITIONAL SPONSORSHIPS)

CS FOR HOUSE BILL NO. 16(FIN) am

IN THE LEGISLATURE OF THE STATE OF ALASKA

TWENTY-THIRD LEGISLATURE - FIRST SESSION

BY THE HOUSE FINANCE COMMITTEE

Amended: 3/26/03
Offered: 3/19/03

Sponsor(s): REPRESENTATIVES FATE, Whitaker, Chenault, Holm, Kohring, Heinze, Crawford, Guttenberg, Lynn

SENATORS Elton, Wagoner, Seekins, Lincoln, Dyson, Guess, Bunde, Wilken, Green, Cowdery, Ben Stevens, Ellis, Olson

A BILL

FOR AN ACT ENTITLED

"An Act amending, for purposes of the Alaska Stranded Gas Development Act, the standards applicable to determining whether a proposed new investment constitutes a qualified project, the standards used to determine whether a person or group qualifies as a project sponsor or project sponsor group, and the deadline for applications relating to the development of contracts for payments in lieu of taxes and for royalty adjustments that may be submitted for consideration, and modifying the conditions bearing on the use of independent contractors to evaluate applications or to develop contract terms; providing statements of intent for the Act relating to use of project labor agreements and to reopening of contracts; and providing for an effective date."

BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF ALASKA:

*** Section 1.** The uncodified law of the State of Alaska is amended by adding a new section to read:

LEGISLATIVE INTENT. It is the intent of the legislature that

(1) in awarding contracts under the Alaska Stranded Gas Development Act, a qualified sponsor or qualified sponsor group and contractors of the qualified sponsor or qualified sponsor group may develop and enter into project labor agreements with appropriate collective bargaining organizations for each project for which a contract is entered into; and

(2) each contract for payments in lieu of taxes and for royalty adjustments entered into under the Alaska Stranded Gas Development Act contain a provision by which the contract may be reopened by any party to the contract; the subject matter of the reopening may be dealt with through the use of arbitration proceedings agreed on by the parties.

*** Sec. 2.** AS 43.82.100 is amended to read:

Sec. 43.82.100. Qualified project. Based on information available to the commissioner, the commissioner may determine that a proposal for new investment is a qualified project under this chapter [ONLY] if the project

(1) **<u>principally involves</u>**

<u>(A) the transportation of natural gas by pipeline to one or more markets, together with any associated processing or treatment;</u>

<u>(B)</u> [IS A PROJECT FOR] the export of liquefied natural gas **<u>from the state to one or more other states or countries; or</u>**

<u>(C) any other technology that commercializes the shipment of natural gas within the state or from the state to one or more other states or countries</u>;

(2) would produce at least 500,000,000,000 cubic feet of stranded gas within 20 years from the commencement of commercial operations; and

(3) is capable, subject to applicable commercial regulation and technical and economic considerations, of making gas available to meet the reasonably foreseeable demand in this state for gas within the economic proximity of the project.

*** Sec. 3.** AS 43.82.110 is amended to read:

Sec. 43.82.110. Qualified sponsor or qualified sponsor group. The commissioner may determine that a person or group is a qualified sponsor or qualified sponsor group if the person or a member of the group

(1) intends to own an equity interest in a qualified project, intends to

commit gas that it owns to a qualified project, or holds the permits that the department determines are essential to construct and operate a qualified project; and

(2) meets one or more of the following criteria:

(A) owns a working interest in at least 10 percent of the stranded gas proposed to be developed by a qualified project;

(B) has the right to purchase at least 10 percent of the stranded gas proposed to be developed by a qualified project;

(C) has the right to acquire, control, or market at least 10 percent of the stranded gas proposed to be developed by a qualified project;

(D) has a net worth equal to at least **<u>10</u>** [33] percent of the estimated cost of constructing a qualified project;

(E) has an unused line of credit equal to at least **<u>15</u>** [25] percent of the estimated cost of constructing a qualified project.

*** Sec. 4.** AS 43.82.170 is amended to read:

Sec. 43.82.170. Application deadline. The commissioner of revenue or the commissioner of natural resources may not act on an application for a contract submitted under AS 43.82.120 unless the application is received by the Department of Revenue no later than **<u>March 31, 2005</u>** [JUNE 30, 2001].

*** Sec. 5.** AS 43.82.240(a) is amended to read:

(a) The commissioner may use **<u>independent contractors</u>** [AN INDEPENDENT CONTRACTOR] to assist in the evaluation of an application or in the development of contract terms under AS 43.82.200. The commissioner may condition the development of a contract under AS 43.82.020 on an agreement by the applicant to reimburse the state for the **<u>reasonable</u>** expenses of **<u>independent contractors</u>** [AN INDEPENDENT CONTRACTOR] under this section. **<u>A reimbursement of expenses that is required in an agreement authorized by this subsection may not exceed $1,500,000 for each application.</u>**

*** Sec. 6.** This Act takes effect immediately under AS 01.10.070(c).

Alaska Stranded Gas Development Act
(as amended in 2003)

Sec. 43.82.010. Purpose.

The purpose of this chapter is to

(1) encourage new investment to develop the state's stranded gas resources by authorizing establishment of fiscal terms related to that new investment without significantly altering tax and royalty methodologies and rates on existing oil and gas infrastructure and production;

(2) allow the fiscal terms applicable to a qualified sponsor or the members of a qualified sponsor group, with respect to a qualified project, to be tailored to the particular economic conditions of the project and to establish those fiscal terms in advance with as much certainty as the Constitution of the State of Alaska allows; and

(3) maximize the benefit to the people of the state of the development of the state's stranded gas resources.

Sec. 43.82.020. Contracts for payments in lieu of other taxes and for royalty adjustments.

The commissioner may, under this chapter, negotiate terms for inclusion in a proposed contract with a qualified sponsor or qualified sponsor group providing for

(1) periodic payment in lieu of one or more taxes that otherwise would be imposed by the state or a municipality on the qualified sponsor or members of the qualified sponsor group as a consequence of the sponsor's or group's participation in an approved qualified project under this chapter; and

(2) certain adjustments regarding royalty under AS 43.82.220 .

Sec. 43.82.100. Qualified project.

Based on information available to the commissioner, the commissioner may determine that a proposal for new investment is a qualified project under this chapter ~~only~~ if the project

(1) principally involves

(A) the transportation of natural gas by pipeline to one or more markets, together with any associated processing or treatment;

(B) ~~is a project for~~ the export of liquefied natural gas from the state to one or more other states or countries; or

(C) any other technology that commercializes the shipment of natural gas within the state or from the state to one or more other states or countries;

(2) would produce at least 500,000,000,000 cubic feet of stranded gas within 20 years from the commencement of commercial operations; and

(3) is capable, subject to applicable commercial regulation and technical and economic considerations, of making gas available to meet the reasonably foreseeable demand in this state for gas within the economic proximity of the project.

Sec. 43.82.110. Qualified sponsor or qualified sponsor group.

The commissioner may determine that a person or group is a qualified sponsor or qualified sponsor group if the person or a member of the group

(1) intends to own an equity interest in a qualified project, intends to commit gas that it owns to a qualified project, or holds the permits that the department determines are essential to construct and operate a qualified project; and

(2) meets one or more of the following criteria:

(A) owns a working interest in at least 10 percent of the stranded gas proposed to be developed by a qualified project;

(B) has the right to purchase at least 10 percent of the stranded gas proposed to be developed by a qualified project;

(C) has the right to acquire, control, or market at least 10 percent of the stranded gas proposed to be developed by a qualified project;

(D) has a net worth equal to at least ~~33~~ 10 percent of the estimated cost of constructing a qualified project;

(E) has an unused line of credit equal to at least ~~25~~ 15 percent of the estimated cost of constructing a qualified project.

Sec. 43.82.120. Applications.

(a) A qualified sponsor or qualified sponsor group may submit to the department an application for development of a contract under AS 43.82.020 evidencing that the requirements of AS 43.82.100 and 43.82.110 are met. The application must be submitted in the manner and form and contain the information required by the department.

(b) Along with an application submitted under (a) of this section, an applicant shall submit a proposed project plan for a qualified project that contains the following information based on the information known to the applicant at the time of application:

(1) a description of the work accomplished as of the date of the application to further the project;

(2) a schedule of proposed development activity leading to the projected commencement of commercial operations of the project;

(3) a description of the development activity proposed to be accomplished under the proposed project plan;

(4) a description of each lease or property that the applicant believes to contain the stranded gas that would be developed if the project was built;

(5) a description of the methods and terms under which the applicant is prepared to make gas available to meet the reasonably foreseeable demand in this state for gas within the economic proximity of the project during the term of the proposed contract, including proposed pipeline transportation and expansion rules if pipeline transportation is a part of the proposed project;

(6) a detailed description of options to mitigate the increased demand for public services and other negative effects caused by the project;

(7) a detailed description of options for the safe management and operation of the project once it is constructed;

(8) other information that the commissioner of revenue, in consultation with the commissioner of natural resources, considers necessary to make a determination that

(A) the work accomplished as of the date of application, the schedule of proposed development activity, and the development activity proposed to be accomplished under the proposed project plan reflect a proposal for diligent development on the part of the applicant;

(B) the proposed project plan does not materially conflict with the obligations of a lessee to the state under a lease or under a pool, unit, or other agreement with the state; and

(C) the proposed project plan describes satisfactory methods and terms for accommodating reasonably foreseeable demand for gas in this state within the economic proximity of the project during the term of the proposed contract.

(c) The requirements of (b) of this section do not diminish the obligations of a qualified sponsor or member of a qualified sponsor group to the state or restrict the authority of the commissioner of revenue or the commissioner of natural resources under any other law or agreement relating to a plan of development for a lease, pool, or unit.

Sec. 43.82.130. Qualified project plan.

A proposed project plan submitted under AS 43.82.120 may be approved as a qualified project plan under AS 43.82.140 if the proposed project plan

(1) reflects a proposal for diligent development of the project on the part of the applicant;

(2) does not materially conflict with the obligations of a lessee to the state under a lease or under a pool, unit, or other agreement with the state; and

(3) describes satisfactory methods and terms for making gas available to meet the reasonably foreseeable demand in this state for gas within the economic proximity of the project during the term of the proposed contract.

Sec. 43.82.140. Review of applications and determination of qualifications.

(a) The commissioner shall review an application submitted under AS 43.82.120 to determine whether the provisions of AS 43.82.100 concerning a qualified project and AS 43.82.110 concerning a qualified sponsor or qualified sponsor group have been met. The commissioner may approve an application only if those provisions have been met.

(b) If the commissioner approves an application under (a) of this section, the commissioner and the commissioner of natural resources shall review the proposed project plan submitted with the application to determine whether the provisions of AS 43.82.130 have been met. The commissioner may approve the proposed project plan as a qualified project plan only if the commissioner of natural resources concurs in the approval.

(c) The commissioner shall send to the applicant written notice of and the reasons for the determinations made under (a) and (b) of this section.

Sec. 43.82.150. Actions challenging determinations on applications.

(a) Only an applicant under AS 43.82.120 who is aggrieved by a determination of the commissioner of revenue or the commissioner of natural resources under AS 43.82.140 may seek judicial review of the determination.

(b) The only grounds for judicial review of a determination made under AS 43.82.140 are

(1) failure to follow the qualification and application procedures set out in AS 43.82.100 - 43.82.180; or

(2) abuse of discretion that is so capricious, arbitrary, or confiscatory as to constitute a denial of due process.

Sec. 43.82.160. Multiple applications for similar or competing qualified projects.

Nothing in this chapter prohibits different qualified sponsors or different qualified sponsor groups from submitting applications under AS 43.82.120 relating to similar or competing qualified projects or prohibits the commissioner of revenue or the commissioner of natural resources from reviewing and approving applications and proposed project plans under AS 43.82.140 relating to similar or competing qualified projects.

Sec. 43.82.170. Application deadline.

The commissioner of revenue or the commissioner of natural resources may not act on an application for a contract submitted under AS 43.82.120 unless the application is received by the Department of Revenue no later than ~~June 30, 2001~~March 31, 2005.

Sec. 43.82.180. Withdrawal of applications.

Subject to the terms of a reimbursement agreement under AS 43.82.240 or other agreement with the Department of Revenue, the Department of Natural Resources, the commissioner of revenue, or the commissioner of natural resources affecting the withdrawal of an application, a qualified sponsor or qualified sponsor group may withdraw an application submitted under AS 43.82.120 at any time before the date that the commissioner of revenue submits a contract to the governor under AS 43.82.430 without further obligation under this chapter.

Sec. 43.82.200. Contract development.

If the commissioner approves an application and proposed project plan under AS 43.82.140 , the commissioner may develop a contract that may include

(1) terms concerning periodic payment in lieu of one or more taxes as provided in AS 43.82.210 ;

(2) terms developed under AS 43.82.220 relating to

(A) timing and notice of the state's right to take royalty in kind or in value; and

(B) royalty value;

(3) terms regarding the hiring of Alaska residents and contracting with Alaska businesses under AS 43.82.230 ;

(4) terms regarding periodic payment to, or an equity or other interest in a project for, municipalities under AS 43.82.500 ;

(5) terms regarding arbitration or alternative dispute resolution procedures;

(6) terms and conditions for administrative termination of a contract under AS 43.82.445 ; and

(7) other terms or conditions that are

(A) necessary to further the purposes of this chapter; or

(B) in the best interests of the state.

Sec. 43.82.210. Contract terms relating to payment in lieu of one or more taxes.

(a) If the commissioner approves an application and proposed project plan under AS 43.82.140 , the commissioner may develop proposed terms for inclusion in a contract under AS 43.82.020 for periodic payment in lieu of one or more of the following taxes that otherwise would be imposed by the state or a municipality on the qualified sponsor or member of a qualified sponsor group as a consequence of participating in an approved qualified project:

(1) oil and gas production taxes and oil surcharges under AS 43.55;

(2) oil and gas exploration, production, and pipeline transportation property taxes under AS 43.56;

(3) [Repealed, Sec. 6 ch 34 SLA 1999].

(4) Alaska net income tax under AS 43.20;

(5) municipal sales and use tax under AS 29.45.650 - 29.45.710;

(6) municipal property tax under AS 29.45.010 - 29.45.250 or 29.45.550 - 29.45.600;

(7) municipal special assessments under AS 29.46;

(8) a comparable tax or levy imposed by the state or a municipality after June 18, 1998;

(9) other state or municipal taxes or categories of taxes identified by the commissioner.

(b) If the commissioner chooses to develop proposed terms under (a) of this section, the commissioner shall, if practicable and consistent with the long-term fiscal interests of the state, develop the terms in a manner that attempts to balance the following principles:

(1) the terms should, in conjunction with other factors such as cost reduction of the project, cost overrun risk reduction of the project, increased fiscal certainty, and successful marketing, improve the competitiveness of the approved qualified project in relation to other development efforts aimed at supplying the same market;

(2) the terms should accommodate the interests of the state, affected municipalities, and the project sponsors under a wide range of economic conditions, potential project structures, and marketing arrangements;

(3) the state's and affected municipalities' combined share of the economic rent of the approved qualified project under the contract should be relatively progressive; that is, the state's and affected municipalities' combined annual share of the economic rent of the approved qualified project generally should not increase when there are decreases in project profitability, or decrease when there are increases in project profitability;

(4) the state's and affected municipalities' combined share of the economic rent of the approved qualified project under the contract should be relatively lower in the earlier years than in the later years of the approved qualified project;

(5) the terms should allow the project sponsors to retain a share of the economic rent of the approved qualified project that is sufficient to compensate the sponsors for risks under a range of economic circumstances;

(6) the terms should provide the state and affected municipalities with a significant share of the economic rent of the approved qualified project, when discounted to present value, under favorable price and cost conditions;

(7) the method for calculating the periodic payment in lieu of certain taxes under the contract should be clear and unambiguous; and

(8) while cost calculations for the approved qualified project under the contract should be based on amounts that closely approximate actual costs, agreed-upon formulas reflecting reasonable economic assumptions should be used if possible to promote administrative certainty and efficiency.

(c) Except as provided in (b) of this section, the commissioner's discretion under this section in developing proposed terms for a contract under AS 43.82.020 is not limited to consideration of the economic rent of the approved qualified project.

Sec. 43.82.220. Contract terms relating to royalty.

(a) Notwithstanding any contrary provisions of AS 38, the commissioner of natural resources, with the concurrence of the commissioner of revenue and the affected parties holding a state lease or unit agreement, may develop proposed terms for inclusion in a contract under AS 43.82.020 that modify the timing and notice provisions of the applicable oil and gas leases and unit agreements pertaining to the state's rights to receive its royalty on gas in kind or in value if

(1) the viability of the approved qualified project depends on long-term gas purchase and sale agreements;

(2) certainty over time regarding the quantity of royalty gas that the state may be taking in kind is needed to secure the long-term purchase and sale agreements;

(3) the specified period of the state's commitment to take its royalty share in value or in kind does not exceed the term of the purchase and sale agreements; and

(4) the modification does not impair the ability of the approved qualified project or the state to meet the reasonably foreseeable demand in this state for gas within economic proximity of the project during the term of the contract developed under AS 43.82.020 .

(b) Notwithstanding any contrary provisions of AS 38, the commissioner of natural resources, with the concurrence of the commissioner of revenue and the affected parties holding a state lease or unit agreement, may develop proposed terms for inclusion in a contract under AS 43.82.020 that establish a valuation method for the state's royalty share of the gas production from an approved qualified project.

(c) The commissioner of revenue shall include any proposed terms relating to royalty developed in accordance with this section in the proposed contract under AS 43.82.400 .

(d) Nothing in this chapter permits modification of the state's rights that relate to timing, notice, and rights to receive oil royalty in kind or in value under oil and gas leases or unit agreements.

Sec. 43.82.230. Contract terms relating to hiring of Alaska residents and contracting with Alaska businesses.

(a) The commissioner shall include in a contract under AS 43.82.020 a term requiring the qualified sponsor or qualified sponsor group and contractors of the qualified sponsor or qualified sponsor group to comply with all valid federal, state, and municipal laws relating to hiring Alaska residents and contracting with Alaska businesses to work in the state on the approved qualified project and not to discriminate against Alaska residents or Alaska businesses. Within the constraints of law, the commissioner shall also include in a contract under AS 43.82.020 a term that requires the qualified sponsor or qualified sponsor group and contractors of the qualified sponsor or qualified sponsor group to employ Alaska residents and to contract with Alaska businesses to work in the state on the approved qualified project to the extent the residents and businesses are available, competitively priced, and qualified.

(b) The commissioner shall include in a contract under AS 43.82.020 a term requiring the qualified sponsor or qualified sponsor group and contractors of the qualified sponsor or qualified sponsor group to

(1) advertise for available positions in newspapers in the location where the work is to be performed and in other publications distributed throughout the state, including in rural areas; and

(2) use Alaska job service organizations located throughout the state and not just in the location where the work is to be performed in order to notify Alaskans of work opportunities on the approved qualified project.

(c) Subject to the voluntary agreement of the qualified sponsor, the commissioner may include a term in the contract providing for incentives to encourage training and hiring of Alaska residents.

(d) This section does not create or abridge individual rights and does not create a private right of action for any person.

(e) For purposes of this section,

(1) "Alaska business" means a firm or contractor that

(A) has held an Alaska business license for the preceding 12 months;

(B) maintains, and has maintained for the preceding 12 months, a place of business in the state that competently and professionally deals in supplies, services, or construction of the nature required for the approved qualified project; and

(C) is

(i) a sole proprietorship and the proprietor is an Alaska resident;

(ii) a partnership and more than 50 percent of the partnership interest is held by Alaska residents;

(iii) a limited liability company and more than 50 percent of the membership interest is held by Alaska residents;

(iv) a corporation that has been incorporated in the state or is authorized to do business in the state; or

(v) a joint venture and a majority of the venturers qualify as Alaska businesses under this paragraph;

(2) "Alaska job service organizations" means those offices maintained by the state and recommended by the Department of Labor and Workforce Development whose functions are to aid the unemployed or underemployed in finding employment;

(3) "Alaska resident" means a natural person who

(A) receives a permanent fund dividend under AS 43.23; or

(B) is registered to vote under AS 15 and qualifies for a resident fishing, hunting, or trapping license under AS 16;

(4) "available," as applied to an Alaska resident or Alaska business, means that the resident or business is available for employment at the time required and is located anywhere in the state, not just in the area of the state where the work is to be performed;

(5) "qualified," as applied to an Alaska resident or Alaska business, means that the resident or business possesses the requisite education, training, skills, certification, or experience to perform the work necessary for a particular position or to perform a particular service.

Sec. 43.82.240. Use of an independent contractor.

(a) The commissioner may use ~~an independent contractor~~independent contractors to assist in the evaluation of an application or in the development of contract terms under AS 43.82.200 . The commissioner may condition the development of a contract under AS 43.82.020 on an agreement by the applicant to reimburse the state for the reasonable expenses of ~~an independent contractor~~ independent contractors under this section. A reimbursement of expenses that is required in an agreement authorized by this subsection may not exceed $1,500,000 for each application.

(b) An independent contractor selected under this section must sign an agreement regarding confidentiality and disclosures consistent with the determinations made under AS 43.82.310 before the contractor may review information that is determined confidential under AS 43.82.310 .

(c) Selection of an independent contractor under this section is not subject to AS 36.30 (State Procurement Code).

Sec. 43.82.250. Term of contract; effective date.

The term of a contract developed under AS 43.82.020 may be for no longer than is necessary to develop the stranded gas that is subject to the contract; however, the term of the contract may not exceed 35 years from the commencement of commercial operations of the approved qualified project.

Sec. 43.82.260. Change of parties to an application or a contract; assignment of interests.

(a) A qualified sponsor or member of a qualified sponsor group may assign an interest in or add or withdraw a party to an application under AS 43.82.120 only if the commissioner has

(1) made a finding that the assignment, addition, or withdrawal is consistent with the requirements of AS 43.82.110 ; and

(2) given prior written approval for the assignment, addition, or withdrawal.

(b) A contract developed under this chapter may provide for the assignment to or withdrawal of a qualified sponsor or member of a qualified sponsor group.

(c) Upon being added to an application under this section, a party becomes a qualified sponsor or a member of a qualified sponsor group, as appropriate, for the relevant project.

(d) The commissioner may not unreasonably withhold approval under (a) of this section, but may condition the approval in any way reasonably necessary to protect the fiscal interests of the state and to further the purposes of this chapter.

(e) For purposes of this section, an assignment includes a transfer of stock or a partnership interest in a manner that changes control of a qualified sponsor or member of a qualified sponsor group.

Sec. 43.82.270. Project plans and work commitments.

A contract under AS 43.82.020 must include the qualified project plan approved under AS 43.82.140 and provisions for updating the plan at reasonable intervals until the commencement of commercial operations of the approved qualified project. The commissioner of revenue, in consultation with the commissioner of natural resources, may, as a term in a contract under AS 43.82.020 , include work commitments or other obligations in the contract to be accomplished before the commencement of commercial operations of the approved qualified project.

Sec. 43.82.300. Requests for information.

The commissioner of revenue or the commissioner of natural resources may request from an applicant information that the respective commissioner determines is necessary to perform the respective commissioner's responsibilities under AS 43.82.140 . If the application is approved under AS 43.82.140 , the respective commissioner shall require the successful applicant to provide financial, technical, and market information regarding the qualified project that the respective commissioner determines is necessary for the purpose of developing contract terms for the qualified project under AS 43.82.200 . If requested information is not provided, the commissioner of revenue may not continue to review the application under AS 43.82.140 or develop the contract under AS 43.82.200 - 43.82.270, as applicable.

Sec. 43.82.310. Disclosure of information; confidentiality.

(a) An applicant may request confidential treatment of information that the applicant provides under AS 43.82.300 by clearly identifying the information and the reasons supporting the request for confidential treatment. The commissioner of revenue or the commissioner of natural resources, as appropriate, shall keep the information confidential until the commissioner determines whether the requirements of (b) of this section are met. If the commissioner of revenue or the commissioner of natural resources has not made a determination under (b) of this section within 14 days after receiving a request for confidential treatment, the request is considered denied. If the appropriate commissioner determines that the information does not meet the requirements of (b) of this section or if the commissioner fails to make a determination within 14 days, the commissioner shall return the information and any copies of it at the request of the applicant. If the commissioner of revenue or the commissioner of natural resources, as appropriate, returns information under this subsection, the commissioner shall cease review of the application or cease contract development under AS 43.82.200 - 43.82.270, as appropriate, unless the commissioner determines that the returned information is unnecessary to make a determination on the application or to develop contract terms under AS 43.82.200 - 43.82.270.

(b) If requested by the applicant, information provided to the commissioner of revenue or the commissioner of natural resources under AS 43.82.300 shall be kept confidential if the commissioner receiving the information determines, upon an adequate showing by the applicant, that the information

(1) is a trade secret or other proprietary research, development, or commercial information that the applicant treats as confidential;

(2) affects the applicant's competitive position; and

(3) has commercial value that may be significantly diminished by public disclosure or that public disclosure is not in the long-term fiscal interests of the state.

(c) Information determined to be confidential under (b) of this section is confidential under that subsection only so long as is necessary to protect the competitive position of the applicant, to prevent the significant diminution of the commercial value of the information, or to protect the long-term fiscal interests of the state. The commissioner of revenue or the commissioner of natural resources, as appropriate, may not release information that the commissioner has previously determined to be confidential under (b) of this section without providing the applicant notice and an opportunity to be heard.

(d) Notwithstanding the limitation in (c) of this section, the Department of Revenue and the Department of Natural Resources may provide to one another, to the Department of Law, to the legislature, and to the Office of the Governor any information provided under AS 43.82.300 relevant to the implementation of this chapter or to the enforcement of state or federal laws. Information that is exchanged under this subsection that was determined to be confidential under (b) of this section remains confidential except as provided in (c) of this section. The portions of the records and files of the Department of Revenue, the Department of Natural Resources, the Department of Law, the legislature, and the Office of the Governor that reflect, incorporate, or analyze information that is determined to be confidential under (b) of this section are not public records except as provided in (c) of this section.

(e) Notwithstanding the limitation in (c) of this section, information that is determined to be confidential under (b) of this section shall be disclosed on request by the commissioner of revenue, the commissioner of natural resources, or the attorney general to a legislator; to the legislative auditor; and, as directed by the chair or vice-chair of the Legislative Budget and Audit Committee, to the director of legislative finance, to the permanent employees of those divisions who are responsible for evaluating a contract under AS 43.82.020, and to agents or contractors of the legislative auditor or the director of legislative finance who are engaged to evaluate a contract under AS 43.82.020 . Information that is determined to be confidential under (b) of this section may also be disclosed by the commissioner of revenue or the commissioner of natural resources to an independent contractor under AS 43.82.240 or to a municipal advisory group established under AS 43.82.510 . Before confidential information is disclosed under this subsection, the person receiving the information must sign an appropriate confidentiality agreement.

(f) If the commissioner of revenue chooses to develop a contract under AS 43.82.020 , the portions of the records and files of the Department of Revenue, the Department of Natural Resources, the Department of Law, and a municipal advisory group established under AS 43.82.510 that reflect, incorporate, or analyze information that is relevant to the development of the position or strategy of the commissioner of revenue, the commissioner of natural resources, or the attorney general with respect to a particular provision that may be incorporated into the contract are not public records until the commissioner of revenue gives public notice under AS 43.82.410 of the commissioner's preliminary findings and determination under AS 43.82.400 . Nothing in this subsection

(1) makes a record or file of the Department of Revenue, the Department of Natural Resources, or the Department of Law a public record that otherwise would not be a public record under AS 40.25.100 - 40.25.220;

(2) affects the confidentiality provisions of (a) - (e) of this section; or

(3) abridges a privilege recognized under the laws of this state, whether at common law or by statute or by court rule.

Sec. 43.82.400. Preliminary findings and determination regarding the contract.

(a) If the commissioner develops a proposed contract under AS 43.82.200 - 43.82.270, the commissioner shall

(1) make preliminary findings and a determination that the proposed contract terms are in the long-term fiscal interests of the state and further the purposes of this chapter; and

(2) prepare a proposed contract that includes those terms and shall submit the contract to the governor.

(b) To make the preliminary findings and determination required by (a)(1) of this section, the commissioner shall compare the projected public revenue anticipated from the approved qualified project with the estimated operating and capital costs of the additional state and municipal services anticipated to arise from the construction and operation of the approved qualified project. The commissioner shall address the reasonably foreseeable effects of the proposed contract on the public revenue.

(c) In conjunction with the making of preliminary findings and determination required by (a)(1) of this section, the commissioner shall describe the principal factors, including the projected price of gas, projected production rate or volume of gas, and projected recovery, development, construction, and operating costs, upon which the determination made under (a)(1) of this section is based. If the commissioner has previously submitted a proposed contract to the governor, the commissioner shall describe any material differences between the terms of the currently proposed contract and the previously proposed contract.

Sec. 43.82.410. Notice and comment regarding the contract.

The commissioner shall

(1) give reasonable public notice of the preliminary findings and determination made under AS 43.82.400 ;

(2) make copies of the proposed contract, the commissioner's preliminary findings and determination, and, to the extent the information is not required to be kept confidential under AS 43.82.310 , the supporting financial, technical, and market data, including the work papers, analyses, and recommendations of any independent contractors used under AS 43.82.240 available to the public and to

(A) the presiding officer of each house of the legislature;

(B) the chairs of the finance and resources committees of the legislature; and

(C) the chairs of the special committees on oil and gas, if any, of the legislature;

(3) offer to appear before the Legislative Budget and Audit Committee to provide the committee a review of the commissioner's preliminary findings and determination, the proposed contract, and the supporting financial, technical, and market data; if the Legislative Budget and Audit Committee accepts the commissioner's offer, the committee shall give notice of the committee's meeting to the public and all members of the legislature; if the financial, technical, and market data that is to be provided must be kept confidential under AS 43.82.310 , the commissioner may not release the confidential information during a public portion of a committee meeting; and

(4) establish a period of at least 30 days for the public and members of the legislature to comment on the proposed contract and the preliminary findings and determination made under AS 43.82.400 .

Sec. 43.82.420. Coordination of public and legislative review.

To the extent practicable, the commissioner shall coordinate the public comment opportunity provided under AS 43.82.410 (4) with a review by the Legislative Budget and Audit Committee under AS 43.82.410 (3).

Sec. 43.82.430. Final findings, determination, and proposed amendments; execution of the contract.

(a) Within 30 days after the close of the public comment period under AS 43.82.410 (4), the commissioner of revenue shall

(1) prepare a summary of the public comments received in response to the proposed contract and the preliminary findings and determination;

(2) after consultation with the commissioner of natural resources, if appropriate, and with the pertinent municipal advisory group established under AS 43.82.510 , prepare a list of proposed amendments, if any, to the proposed contract that the commissioner of revenue determines are necessary to respond to public comments;

(3) make final findings and a determination as to whether the proposed contract and any proposed amendments prepared under (2) of this subsection meet the requirements and purposes of this chapter.

(b) After considering the material described in (a) of this section and securing the agreement of the other parties to the proposed contract regarding any proposed amendments prepared under (a) of this section, if the commissioner determines that the contract is in the long-term fiscal interests of the state, the commissioner shall submit the contract to the governor.

(c) The commissioner's final findings and determination under (a) of this section are final agency decisions under this chapter.

Sec. 43.82.435. Legislative authorization.

The governor may transmit a contract developed under this chapter to the legislature together with a request for authorization to execute the contract. A contract developed under this chapter is not binding upon or enforceable against the state or other parties to the contract unless the governor is authorized to execute the contract by law. The state and the other parties to the contract may execute the contract within 60 days after the effective date of the law authorizing the contract.

Sec. 43.82.440. Judicial review.

A person may not bring an action challenging the constitutionality of a law authorizing a contract enacted under AS 43.82.435 or the enforceability of a contract executed under a law authorizing a contract enacted under AS 43.82.435 unless the action is commenced within 120 days after the date that the contract was executed by the state and the other parties to the contract.

Sec. 43.82.445. Administrative termination of a contract.

(a) The commissioner shall include terms in a contract developed under AS 43.82.020 that provide for administrative termination of a party's rights under the procedures and conditions set out in this section if the party has

(1) ceased to meet the requirements of AS 43.82.110 as a qualified sponsor or qualified sponsor group;

(2) intentionally or fraudulently misrepresented, in whole or in part, material facts or circumstances upon which the contract was made;

(3) failed to comply with a condition or material term of the contract or a provision of this chapter; or

(4) failed to comply with the approved qualified project plan or any updated project plan.

(b) Before administrative termination of a contract under this section, the commissioner shall give notice to the parties of the commissioner's intent to terminate the contract and an opportunity to be heard. The commissioner may also provide the parties an opportunity to cure any deficiency that is the basis for the termination if the commissioner determines that curing the deficiency is appropriate under the circumstances.

(c) Notwithstanding (a) and (b) of this section, the commissioner may not administratively terminate a contract after the party has committed full project funding except as provided in (e) of this section.

(d) A party to a contract who is affected by the commissioner's action to terminate under (a) of this section may file an appeal with the superior court under the Alaska Rules of Appellate Procedure.

(e) The commissioner may provide terms and conditions in a contract developed under AS 43.82.020 upon which a party's rights under the contract may be administratively terminated after the party commits full project funding.

Sec. 43.82.500. Obligation to share payments with municipalities.

If the commissioner develops a contract under AS 43.82.020 that includes terms that exempt a party to the contract, and the property, gas, products, and activities associated with the approved qualified project that is subject to the contract, from a municipal tax or assessment in accordance with AS 29.45.810 or AS 29.46.010 (b), or AS 43.82.200 and 43.82.210, the commissioner shall include a term in the contract that the party pay a portion of the periodic payments due under the contract to the revenue-affected municipality.

Sec. 43.82.505. Payments to economically affected municipalities.

If the commissioner executes a contract under AS 43.82.020 that will produce one or more economically affected municipalities, the commissioner shall include a term in the contract that provides for a portion of the periodic payments to the economically affected municipalities under the principles in AS 43.82.520 .

Sec. 43.82.510. Municipal advisory group.

(a) If the commissioner approves an application and proposed project plan under AS 43.82.140 and decides to develop a contract under AS 43.82.020 and 43.82.200, the commissioner shall notify each revenue-affected municipality and economically affected municipality.

(b) The mayor of a municipality notified by the commissioner under (a) of this section may appoint one representative to a municipal advisory group in relation to the application.

(c) Each municipal advisory group serves until a final action is taken on the application for which the group was appointed.

(d) Each municipal advisory group shall elect a chair.

Sec. 43.82.520. Duties of the commissioner of revenue in relation to municipal participation.

(a) The commissioner shall meet with each municipal advisory group periodically to report on the development of the contract provisions that affect the municipalities.

(b) In developing a contract under AS 43.82.200 - 43.82.270, the commissioner shall ensure that each revenue-affected municipality and economically affected municipality receives a fair and reasonable share of the payments provided under AS 43.82.210 in accordance with the following principles:

(1) the share of the payments to revenue-affected municipalities should be given priority over payments to economically affected municipalities with due regard to the anticipated size of the tax base that the contract would exempt from municipal taxation by revenue-affected municipalities;

(2) the share of the payments to municipalities should be determined with due regard to the anticipated economic and social burdens that would be imposed on the municipality by construction and operation of the project;

(3) the respective shares of the total payments to the state and to municipalities should be fixed in a manner to ensure that their respective interests are aligned;

(4) to the extent practicable, the periodic amounts paid to each of the municipalities should be stable and predictable; and

(5) to the extent practicable, the provisions for sharing payments with municipalities should be consistent with the principles established in AS 43.82.210 (b).

(c) In establishing the municipal shares under (b) of this section, the commissioner shall consult with the pertinent municipal advisory group.

Sec. 43.82.600. Governing law.

If a provision of this chapter conflicts with another provision of state or municipal law, the provision of this chapter governs.

Sec. 43.82.610. Regulations.

The commissioner of revenue, the commissioner of natural resources, and the commissioner of labor and workforce development may adopt regulations to carry out their respective duties under this chapter.

Sec. 43.82.620. Procedures for collection of amounts due; security.

(a) The commissioner may adopt procedures for the collection of amounts due the state under a contract developed under AS 43.82.020 , including the collection of interest and penalties.

(b) The commissioner may require a party to a contract developed under AS 43.82.020 to provide security sufficient to guarantee amounts due under the contract.

Sec. 43.82.630. Reports and audits.

The commissioner may require periodic reports from and may at reasonable intervals conduct audits and inspect the books of a party that has entered into a contract developed under AS 43.82.020 to ensure compliance with the provisions of this chapter and the regulations adopted under this chapter and of the terms of the contract.

Sec. 43.82.640. Annual report of the commissioner of labor and workforce development.

On an annual basis, the commissioner of labor and workforce development shall prepare and present to the legislature a comprehensive report on each party to a contract with the state developed under AS 43.82.020 , and its contractors, regarding the state residency of the employees working in this state on the approved qualified project that is subject to the contract. The commissioner of labor and workforce development shall use state data bases, including data from the quarterly reports by a party to the contract developed under AS 43.82.020 and its contractors for unemployment insurance purposes, to determine state residency of employees regarding compliance with AS 43.82.230 .

Sec. 43.82.900. Definitions.

In this chapter, unless the context requires otherwise,

(1) "affected municipality" means an economically affected municipality or a revenue-affected municipality;

(2) "commencement of commercial operations" means the start of regular deliveries of marketable products from an approved qualified project;

(3) "cubic foot of gas" means the quantity of gas contained in a volume of one cubic foot at a standard temperature of 60 degrees Fahrenheit and a standard absolute pressure of 14.65 pounds per square inch;

(4) "economically affected municipality" means a municipality the commissioner of revenue determines will be reasonably required to provide additional public services under the terms proposed in an application approved under AS 43.82.140 (a); the commissioner may consider historical data from construction of the Trans Alaska Pipeline System, and information submitted by a municipality in making the determination;

(5) "economic proximity" means the distance within which a person may be willing to design, construct, and operate a gas line to provide service to a local consumer;

(6) "economic rent" means the estimated total gross revenue less estimated total costs for a qualified project over the term of a contract under AS 43.82.020 , measured in undiscounted nominal dollars; for purposes of this paragraph, total costs do not include a rate of return on capital, financing costs, or any payments to governments;

(7) "full project funding" means full approval by a party to a contract under AS 43.82.020 for the expenditure of the capital necessary for construction and operation of the approved qualified project that is subject to the contract;

(8) "gas" has the meaning given in AS 43.55.900 ;

(9) "group" means two or more persons;

(10) "lease or property" has the meaning given in AS 43.55.900 ;

(11) "periodic payment" means payment made in lieu of one or more other taxes under a contract under AS 43.82.020 ;

(12) "revenue-affected municipality" means a municipality that the commissioner of revenue reliably expects will be restricted from imposing a tax, or a portion of a tax, as a result of implementation of a contract developed under this chapter;

(13) "stranded gas" means gas that is not being marketed due to prevailing costs or price conditions as determined by an economic analysis by the commissioner for a particular project.

Sec. 43.82.990. Short title.

This chapter may be cited as the Alaska Stranded Gas Development Act.

Appendix A.3	Annual Reports for Members of Sponsor Group

BP Annual Report

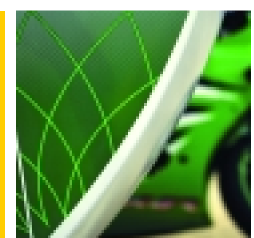
ConocoPhillips Annual Report

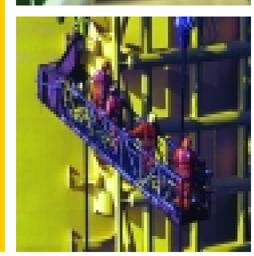
ExxonMobil Annual Report

Annual Report 2002

bp

Our business is strong. Our company is soundly managed. Our people are determined to be the best in their field.





Contents

2 Performance highlights

4 Chairman's letter

6 Group chief executive's review

8 Financial and business operating review

20 Environmental and social performance

22 Summary accounts

28 Corporate governance

30 Directors' remuneration report

40 Shareholdings and Annual General Meeting

40 Further information

41 Board of directors

The Annual Report and Accounts for the year ending 31 December 2002 comprises two volumes.

This volume, *Annual Report 2002*, contains the full Directors' Report on pages 1-21, 28-29 and 40-41, the Directors' Remuneration Report on pages 30-39, and a summary of the information in the annual accounts on pages 22-27. This complies with the information required under the Companies (Summary Financial Statement) Regulations 1995.

The full accounts for the year ending 31 December 2002 are contained in a separate volume, *Annual Accounts 2002.*

This volume on its own does not contain sufficient information to allow as full an understanding of the results and state of affairs of BP as when read in conjunction with *Annual Accounts 2002*. Shareholders requiring more detailed information may obtain a copy of *Annual Accounts 2002* on request, free of charge *(see page 40)*.

As BP shares, in the form of ADSs, are listed on the New York Stock Exchange, an Annual Report on Form 20-F will be filed with the US Securities and Exchange Commission in accordance with the US Securities and Exchange Act 1934. This is expected to be filed around the end of March 2003, and copies may be obtained free of charge *(see page 40)*.

BP p.l.c. is the parent company of the BP group of companies. Unless otherwise stated, the text does not distinguish between the activities and operations of the parent company and those of its subsidiary undertakings.

The term 'shareholders' in this report means, unless the context otherwise requires, investors in the equity capital of BP p.l.c., both direct and/or indirect.

The registered office of BP p.l.c. is: 1 St James's Square, London SW1Y 4PD, UK. Telephone: +44 (0)20 7496 4000. Registered in England and Wales No. 102498. Stock exchange symbol 'BP'.

BP's Annual Report and Accounts 2002 may be downloaded from the BP website using the following URLs:

www.bp.com/annualreport2002

www.bp.com/annualaccounts2002

No other material on the BP website, except that found at the cited URLs, forms any part of the Annual Report and Accounts 2002.

Cautionary statement

The Financial and business operating review and other sections of this report contain statements, particularly those regarding possible or assumed future performance, costs, dividends, returns, BP's asset portfolio and changes in it, earnings, cash flow, share repurchases, investment, debt equity ratio, reserves and growth of BP, industry growth and other trend projections, that are forward-looking statements and involve risks and uncertainties. It is believed that the expectations reflected in these statements are reasonable, but actual results may differ from those expressed in such statements, depending on a variety of factors, including: the specific factors identified in the discussions accompanying such forward-looking statements; industry product supply; demand and pricing; political stability and economic growth in relevant areas of the world; development and use of new technology and successful commercial relationships; the actions of competitors; natural disasters and other changes in business conditions; and wars and acts of terrorism or sabotage.

Every day we serve around 13 million customers in more than 100 countries across six continents, providing products that improve their quality of life – fuel for transport, energy for heat and light, and petrochemicals for use in everyday items such as textiles, packaging and health products. Every day more than 100,000 people combine their energy and innovation to make BP one of the world's leading companies.

We face a time of uncertainty, with tensions in international relations, reduced stock market values and an unpredictable economic outlook. Public expectations of the behaviour of corporations grow ever stronger. All these factors must inform every decision we make and every action we take.

Our desire to deliver outstanding performance is matched by a determination to respond to new realities. It demonstrates that BP is a robust and growing business. We have clear objectives and strategy, while being guided by consistent and transparent standards and values.

Performance highlights

These tables and charts show the highlights of BP's achievements in 2002. They reflect more than our financial performance. Our strong underlying profitability has allowed us to increase the dividend compared with 2001, and we are continuing to invest in our future performance. We also made substantial improvements in our underlying environmental and safety performance. We continue to make major financial commitments in all the communities in which we operate.

Owing to the significant acquisitions that took place in 2000, BP is presenting pro forma results, adjusted for special items, in addition to its reported results. This enables shareholders to assess current performance in the context of our past performance and against that of our competitors. The pro forma result is replacement cost profit before exceptional items excluding acquisition amortization as defined in footnote [a] to the reconciliation table *(below)*. The pro forma result, adjusted for special items, has been derived from our UK GAAP accounting information but is not in itself a recognized UK or US GAAP measure. References within *Annual Report 2002* to 'operating result' and 'result' are to pro forma results, adjusted for special items. References to 'fixed assets', 'capital employed', 'operating capital employed' and 'net debt plus equity' are to these measures on a pro forma basis that excludes the fixed asset revaluation adjustment and goodwill consequent upon the Atlantic Richfield Company (ARCO) and Burmah Castrol acquisitions. 'Return', 'return on average capital employed' and the 'net debt ratio' (net debt/net debt plus equity) refer to ratios calculated using these measures.

The financial information for 2001 has been restated to reflect (i) the adoption by the group of Financial Reporting Standard No. 19 'Deferred Tax' (FRS 19) with effect from 1 January 2002 and (ii) the transfer of the solar, renewables and alternative fuels activities from the 'Other businesses and corporate' segment to Gas and Power on 1 January 2002. To reflect this transfer, Gas and Power was renamed Gas, Power and Renewables from the same date.

Key financial measures ($ million)

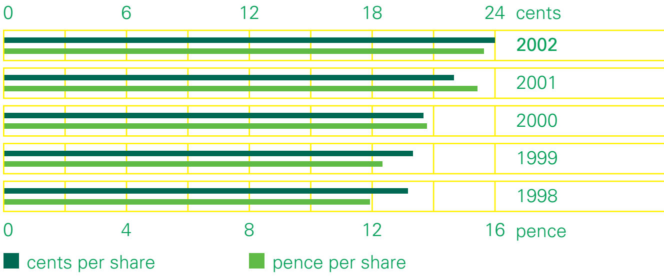
	2002	2001
Pro forma result adjusted for special items	**8,715**	11,559
Replacement cost profit before exceptional items	**4,698**	8,291
Historical cost profit after exceptional items	**6,845**	6,556
Per ordinary shares – cents		
Pro forma result adjusted for special items	**38.90**	51.51
Replacement cost profit before exceptional items	**20.97**	36.95
Historical cost profit after exceptional items	**30.55**	29.21
Dividends per ordinary share – cents	**24.0**	22.0
– pence	**15.638**	15.436
Dividends per ADS – dollars	**1.44**	1.32

Reconciliation of reported profit/loss to pro forma result adjusted for special items ($ million)

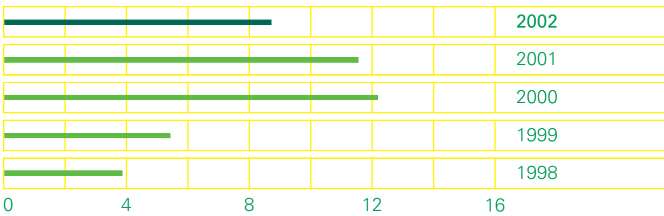
	2002				2001			
	Reported	Acquisition amortization[a]	Special items[b]	**Pro forma result adjusted for special items**	**Reported**	Acquisition amortization[a]	Special items[b]	**Pro forma result adjusted for special items**
Exploration and Production	9,206	1,780	1,019	**12,005**	12,361	1,815	322	**14,498**
Gas, Power and Renewables	354	–	30	**384**	488	–	–	**488**
Refining and Marketing	872	794	415	**2,081**	3,573	770	487	**4,830**
Chemicals	515	–	250	**765**	128	–	114	**242**
Other businesses and corporate	(701)	–	186	**(515)**	(523)	–	73	**(450)**
Replacement cost operating profit	**10,246**	2,574	1,900	**14,720**	**16,027**	2,585	996	**19,608**
Interest expense	(1,279)	–	15	**(1,264)**	(1,670)	–	62	**(1,608)**
Taxation	(4,217)	–	(456)	**(4,673)**	(6,005)	–	(375)	**(6,380)**
Minority shareholders' interest (MSI)	(52)	–	(16)	**(68)**	(61)	–	–	**(61)**
Replacement cost profit before exceptional items	**4,698**	2,574	1,443	**8,715**	**8,291**	2,585	683	**11,559**
Exceptional items, net of tax	1,043				165			
Replacement cost profit after exceptional items	**5,741**				**8,456**			
Stock holding gains (losses), net of MSI	1,104				(1,900)			
Historical cost profit	**6,845**				**6,556**			

[a] Acquisition amortization refers to depreciation relating to the fixed asset revaluation adjustment and amortization of goodwill consequent upon the ARCO and Burmah Castrol acquisitions.
[b] The special items refer to non-recurring charges and credits.

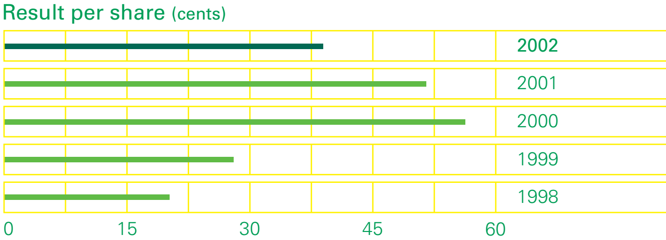
Dividends per share (cents/pence)



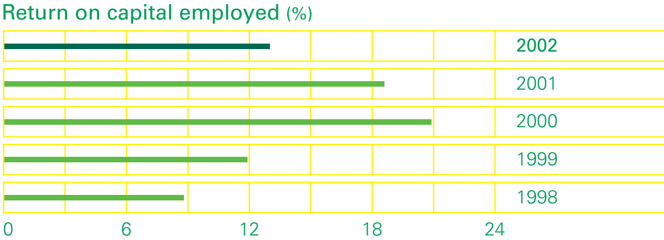
Result ($ billion)



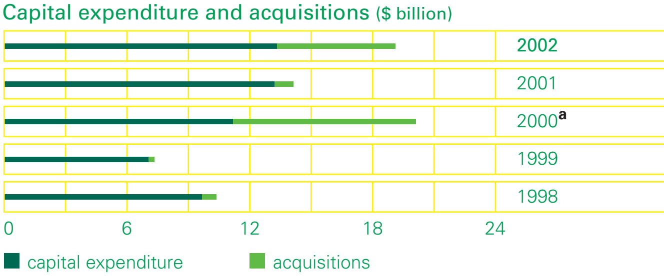
Result per share (cents)



Return on capital employed (%)



Capital expenditure and acquisitions ($ billion)



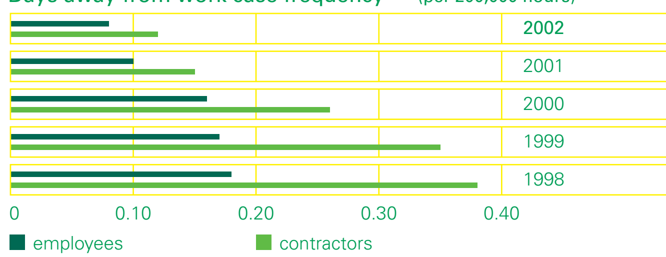
[a]Excludes $27,056 for the ARCO acquisition.

Environmental performance

	2002 BP	**2002 underlying[a]**	2001 BP
Greenhouse gas emissions (million tonnes)[b]	**82.4**	**78.3**	80.5
Total number of spills (>1 barrel)[c]	**761**	**742**	810[d]
Percentage of major operations with ISO 14001[e]	**92**	**94**	73

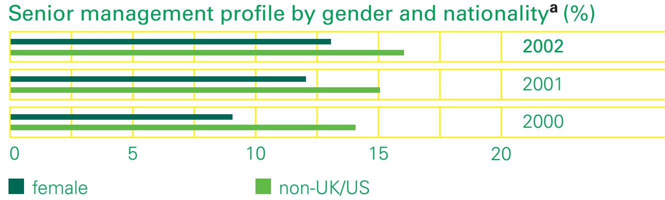
[a]BP operations excluding Veba.
[b]BP share of emissions of carbon dioxide and methane, expressed as an equivalent mass of carbon dioxide.
[c]1 barrel = 159 litres = 42 US gallons.
[d]2001 data has been restated to include all spills, whether the spill reached land or water or was contained.
[e]ISO 14001 is an international environmental management standard.

Days away from work case frequency[a, b] (per 200,000 hours)



[a]An injury or illness that results in a person being unable to work for a day (shift) or more.
[b]2002 data excludes Castrol and Veba contractors and Veba employees.

Senior management profile by gender and nationality[a] (%)



[a]Senior management includes the top 622 positions in BP.

Community investment by region ($ million)

	2002	2001	2000	1999	1998
UK	**13.9**	14.9	15.4	10.4	12.2
(including UK charities	***3.2***	*4.7*	*4.1*	*5.3*	*5.1)*
Rest of Europe	**6.2**	8.0	5.3	3.5	2.6
USA	**46.3**	52.9	46.0	36.4	37.0
Rest of World	**18.8**	18.9	14.9	17.1	13.1
Total	**85.2**	94.7	81.6	67.4	64.9

Community investment by theme ($ million)

	2002	***including UK charities 2002***	2001	*including UK charities 2001*	2000	1999	1998
Community development	**24.3**	***0.7***	33.3	*0.9*	28.2	29.5	15.8
Education	**24.2**	***0.8***	29.5	*2.2*	21.3	14.8	14.6
Environment and health	**19.8**	***1.1***	15.5	*1.2*	8.3	4.7	6.1
Arts and culture	**6.6**	***0.1***	8.2	–	15.0	11.0	13.6
Other	**10.3**	***0.5***	8.2	*0.4*	8.8	7.4	14.8
Total	**85.2**	***3.2***	94.7	*4.7*	81.6	67.4	64.9

Chairman's letter

Dear Shareholder

Weak stock markets worldwide have been driving down share prices, but I am pleased to report that we have been able to increase the total annual dividend per share to 24 cents, thanks to BP's strong underlying performance in 2002. This is a dividend increase in dollar terms of 9.1% over 2001.

This further increase is a testament to the performance we delivered in business conditions that remained difficult throughout the year. It reflects the success of our strategy of continually seeking to improve our portfolio of assets and of establishing leading market positions. The completion of the acquisition of Veba Oil in 2002 is a notable example.

Our fundamental objective is to protect and enhance shareholder value in a sustainable way, in both the short and long term. In order to fulfil this responsibility to our global shareholder base, we place great emphasis on the duties of the non-executive directors. They form a majority on the board and its committees and their role as champions of shareholders' interests is increasingly widely recognized.

We must recognize too that the oil business has a long-term project development cycle and the industry itself is cyclical over an extended period. In these circumstances, the board believes it is strongly in the shareholders' interests to have a number of non-executive directors with longer-term experience of the business. This is particularly so for BP over the next five years as the board works with John Browne to bring on a new executive team and leadership.

As a UK-registered company, we are pleased that our own policies and practices are already substantially in line with the Higgs and Smith reports on governance. In the USA, where we are listed on the NYSE, significant regulatory proposals are currently in the course of implementation. We look forward to monitoring progress as these developments are implemented on both sides of the Atlantic. We do not expect they will cause us to make any significant changes to our existing practice.

A particularly important task of the board is to monitor the way the company manages its approach to opportunities and risks, which may be operational, financial, environmental or ethical. This monitoring includes an annual review of the full range of possible risks, a review that shapes our continuing assessments. The board's committees review the business throughout the year. Their role, too often overlooked, is highlighted in the accompanying box.

We believe that we have robust policies and processes that give the board a clear picture of the business as a whole, and the ability to monitor and assess changes and developments. At the same time, the chief executive and his team must have the freedom and flexibility to exercise the day-to-day judgements needed to run the company.

These policies and processes are all the more important because, as a major international company, we come under intense and varied scrutiny in the societies in which we operate. This comes from regulatory authorities and others representing the interests of people who are affected in some way by our operations – as well as our shareholders, employees and customers.

We also believe that, in addition to serving our customers, the investment, trade, skills and opportunities we bring to countries around the world can be hugely beneficial. We try to have a positive impact on every community in which we work, and aim to operate in a way that does no harm to the environment. Our long-term performance is linked to our success in managing these challenges and our commitment to investment for the future.

Fundamentally, our ability to deliver outstanding performance depends on the work of the more than 100,000 people in BP and on the leadership provided by John Browne and his team. We depend on their determination, experience and creativity. On behalf of the board I would like to recognize their contribution in 2002, and thank them for it.

We have in place the management processes and the exceptional people to respond to challenges. These strengths underpin our commitment to build long-term shareholder value in a sustainable way.

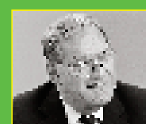
It is essential to the success of our business that we attract and retain exceptional people at all levels, and create the conditions in which they are motivated to be the best in their field. This need shapes our remuneration policies, and we are confident that the current level and structure of executive reward provide the appropriate incentives. Reward is tied to performance and, at senior levels, to the long-term success of the company. The standards we set for performance are both clear and highly demanding, in a very competitive sector. Details of these remuneration policies are set out later in this report. As a board we believe our approach is confirmed by the value we have delivered to shareholders.

Two of our long-serving executive directors are leaving the board. Rodney Chase relinquished his role as deputy chief executive in January 2003. He will retire from the board in April, after a 38-year career with BP. Dr John Buchanan, our chief financial officer for the past six years, retired from the board last November after 33 years' service with BP. We have greatly valued their respective contributions and thank them very much for the part they have played in the development of the business.

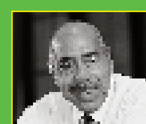
Dick Olver, formerly chief executive of exploration and production and an executive director since 1998, has been appointed to the role of deputy group chief executive. We welcome to the board Dr David Allen, Dr Tony Hayward and John Manzoni, who were appointed executive directors on 1 February 2003.

Peter Sutherland
Chairman
11 February 2003

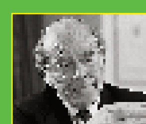
The board's committees are key to the systematic assessment and management of the opportunities and risks facing BP. Particularly important in this process are the three described below. Each committee consists of up to six of our non-executive directors, and plays a vital role in representing the interests of shareholders and testing management decisions, processes and judgements. Further information on the work of these committees and the board as a whole is set out on pages 28 to 29 of this report.



Sir Ian Prosser chairs the **Audit Committee**. It is responsible for monitoring all the reporting, accounting, control and financial aspects of executive management activities.



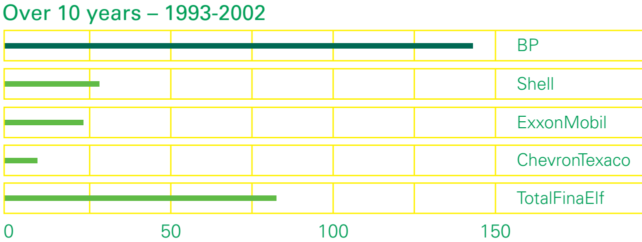
Dr Walter Massey heads the **Ethics and Environment Assurance Committee**. It is responsible for monitoring the non-financial aspects of executive management activities.



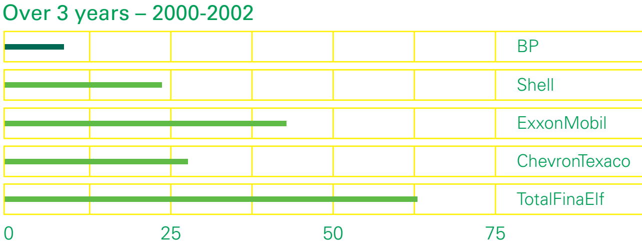
Sir Robin Nicholson is chairman of the **Remuneration Committee**. It is responsible for determining the structure of rewards for the group chief executive and executive directors.

Shareholder returns against the market (%)

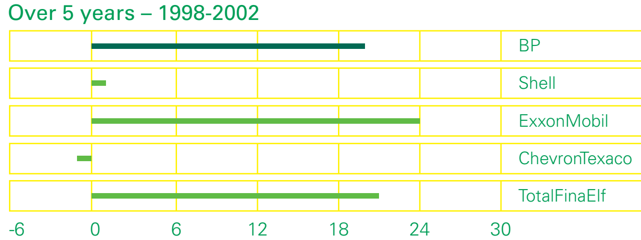
Over 10 years – 1993-2002



Over 3 years – 2000-2002



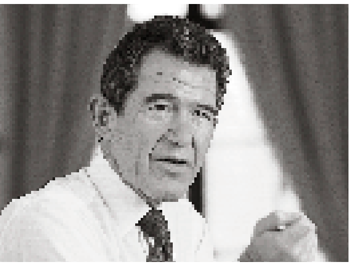
Over 5 years – 1998-2002

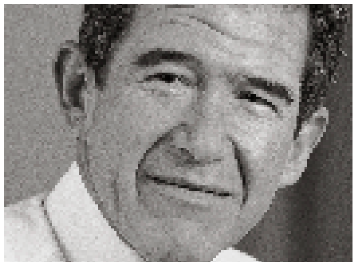


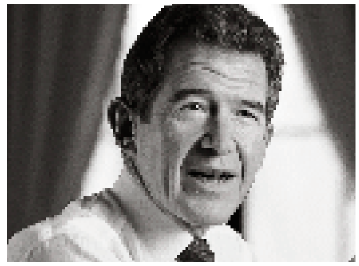
Shareholder returns comprise annual share price movements, with dividends reinvested, for investments held over the period shown.

Shareholder returns against the market reflect the returns generated above or below returns from equivalent investments in the overall market.

Group chief executive's review







Our strategy is to create value from a distinctive set of opportunities, biased towards the upstream, which through a disciplined approach to long-term investment growth can produce returns that are secure and highly competitive.

Managing our business in uncertain times is nothing new to BP. Over the past few years we have demonstrated our ability to instigate change and react swiftly to external influences, time and time again. Despite dramatic swings in exchange rates, interest rates and stock market levels and volatile oil and natural gas prices, we have succeeded in delivering our strategic objectives.

We have always demonstrated our ability to deal with volatility without losing sight of our long-term goals, and have no doubt that we can continue to do so.

Reporting on our performance in 2002 against this backdrop of a volatile and often difficult trading and operating environment calls for a sense of balance and perspective. 2002 was a year in which we had some great successes, in which we failed to meet our production target and, above all, a year in which we learned a great deal.

In 2002, our safety record improved. Fewer people were hurt while working for BP, whether as employees or as contractors. Our performance on safety now compares well with that of the industry leaders.

Our financial performance was strongly competitive with our peers. In a world where natural gas prices and refining margins were significantly lower than in 2001, we delivered a result of $8.7 billion. We generated more than $19 billion of cash from operations. Our return on capital was 13% and our gearing down at below 28%.

We replaced 175% of the reserves we produced, making 2002 the 10th year running in which our reserves replacement exceeded 100% and further growing our inventory of high-quality reserves to renew the company for the future.

In underlying terms – that is, under mid-cycle operating conditions – performance improved by $1.2 billion before tax, against a target of $1.4 billion. As a result of our performance, the board was able to increase the dividend for the year in dollar terms by 9.1% and has announced an intended share buyback programme of $2 billion.

We were not satisfied with everything in 2002. The movement in our absolute stock price reflected the falls in all world markets. In addition, operational and political events gave us production growth of 2.9% – a level that compared very well with that of our competitors but was below our target growth rate of 5.5%. Having allocated capital in 2001-02 to high-value projects in new growth areas, we lacked the flexibility needed to close this gap.

That experience has taught us that production volumes, while potentially an indicator of growth, are only really useful when combined with a balanced view of all the other factors that go to create value.

The missed production target prompted us to undertake a thorough review. This has confirmed that our strategy is sound, on track and creating a business that is distinctive in its capacity to create value – today, tomorrow and subsequently. Our review of strategy also confirmed to me that we have an outstanding team of great people who have a clear understanding of our strategy and are confident about our future. I am most grateful for their dedication and delivery.

The world's need for energy is growing. BP has a strong portfolio of assets and the financial strength to take advantage of new opportunities as they arise. We have a great portfolio of world-class brands. We place much emphasis on clarity in the way we manage our company – setting and communicating governance standards, and implementing rigorous internal review procedures that help us challenge and, as necessary, refresh our ways of working. Our efforts to maintain our year-on-year track record of improvements to the safety performance of all our operations and to reduce the impact of our activities on the environment remain relentless.

Our strategy is to create value from a distinctive set of opportunities, biased towards the upstream, which through a disciplined approach to long-term investment growth can produce returns that are secure and highly competitive. We continue to dispose of those assets that no longer offer us the right performance potential.

In upstream, the key to success is the ability to access and focus on those opportunities that offer material and superior returns. My confidence that we are on the right path stems from our track record in finding giant fields, replacing reserves and the portfolio of projects now under development.

Our investment strategy for 2003-07 is focused on developing five new material upstream profit centres – in the deepwater Gulf of Mexico, Trinidad, Azerbaijan, Angola and Asia Pacific. These should begin to contribute significant earnings and free cash flow during next year and beyond. The development of these new activities is an important moment in the long history of BP – a move analogous for us to the development of the North Sea and Alaska 30 years ago. These new activities not only renew BP for the medium term. They also offer great potential for the longer term, with extensive further resources yet to be discovered.

In addition, we have announced an agreement in principle with the Alfa Group and Access-Renova to combine our interests in Russia to create that country's third largest oil and gas business. The transaction, scheduled for completion in the summer, will result in the formation of our sixth new upstream profit centre.

The strategy for our established upstream assets in areas such as North America and the North Sea is to maximize productivity. We will do this by strict control of capital reinvestment, based on risk and expected returns according to a global ranking, and applying best-in-class operating efficiency.

Our downstream businesses have grown rapidly, with capital employed increasing by 20% per year on average since 1999. Downstream growth potential is centred on four distinctive business areas: refining; retailing; lubricants; and business-to-business marketing. Our approach is to improve operating and overhead costs to best-in-class, to offset increasing competitive pressure and to improve value by careful portfolio choice. Part of our potential is underpinned by the market-leading retail position we have established in Germany with the Veba Oil acquisition.

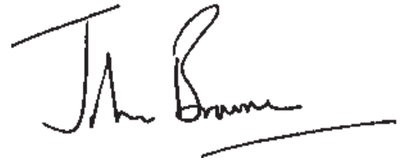
We have transformed our chemicals businesses, strengthening our capability in key product areas following the acquisitions of Erdölchemie and Veba. Now we are working to develop a differentiated, material portfolio based around seven core products with advantaged market positions. The scale of our operations, with production capacity increasing by 32% over the last three years, and the technologies we possess give us competitive advantage.

Our gas, power and renewables business represents an increasingly significant part of our operations as demand for clean and alternative energy sources such as natural gas and solar increases. Our strategy in this area is clear – to maximize the commercial value of the gas we produce by building markets ahead of availability, to develop a material and profitable renewables business and add value to our natural gas liquids business.

Our aspiration to be numbered among the world's great companies remains unchanged. Our goal is to create value – but, of course, maximizing value is not a mechanical process. It requires balance and judgement. If we knew far more about the world and the future than we ever could know, we could then manage the maximization of value with precision. But we cannot. All our experience over the last 95 years, since the company was first established, confirms that value is created through understanding and meeting the needs of all those with whom we do business.

We depend on the satisfaction of consumers with our products, on continued access to capital markets, on the motivation and skills of our people, on good relationships with governments and the communities in which we work and, of course, on our ability to judge the right response to the ever-changing circumstances in the external world.

We cannot neglect any of those issues. We cannot concentrate on one alone – because if we did we would risk endangering them all. Our success in continuing to deliver value for our shareholders will depend on our ability to judge and to maintain the right balance between all those factors.



The Lord Browne of Madingley
Group Chief Executive
11 February 2003

Financial and business operating review

Business environment

The trading environment was challenging during 2002, with natural gas prices and refining margins significantly weaker than in the previous year, owing to the global economic slowdown. Demand improved in most parts of the business after the first half of the year but economic conditions remained sluggish. We have taken a cautious view about the strength of the recovery through 2003.

The adverse business conditions had the greatest impact on refining and marketing. Worldwide refining margins were depressed for much of the year, at nearly half the average level of 2001. They may remain under pressure, although a colder winter after the unusually mild 2001-02 season could help offset the impact of a subdued economic recovery, especially in the key US market. Margins in chemicals were at levels similar to the bottom of previous cycles.

Oil prices were volatile in 2002. The Brent price ranged from around $18 per barrel to above $31 per barrel. The crude oil price increased during the second half of the year, partly reflecting a 'war premium'. Brent prices averaged $25.03 per barrel compared with $24.44 per barrel in 2001.

Natural gas prices in the USA were on average lower than in 2001, at around $3.36 per mmBtu compared with $3.96 per mmBtu, owing to a large surplus of gas in storage during the 2001-02 heating season. Cold weather and the start of a decline in domestic production in the USA brought about a rise in price to around $5 per mmBtu towards the end of 2002.

Results

BP's result for the year was $8,715 million, compared with $11,559 million in 2001. The result per share was 38.90 cents, a decrease of 24%. The replacement cost operating result was $14,720 million (2001 $19,608 million). Replacement cost profit before exceptional items was $4,698 million (2001 $8,291 million).

The special items in 2002 and 2001 are shown in the table below.

The return on average capital employed (ROACE) was 13%, compared with 19% in 2001. On a replacement cost before exceptional items basis, the 2002 return was 6% (2001 11%), and 8% (2001 9%) on a historical cost basis.

During 2002, we achieved $1.2 billion pre-tax underlying performance improvement through volume growth and cost reductions compared with 2001. Underlying performance improvement is an assessment measured after adjusting prices, margins, costs and capacity utilization to levels that we would expect on average over the long term.

Net exceptional gains of $1,168 million before tax included profits from disposal of interests in Ruhrgas and Colonial Pipeline and an electronic payment system, and a gain on the redemption of certain preferred limited partnership interests BP retained following the Altura Energy disposal in 2000. These items were partly offset by provisions for losses on the sale of certain upstream interests announced since the end of 2002.

Interest expense was $1,264 million, compared with $1,608 million in 2001, after adjusting for special charges of $15 million (2001 $62 million) arising from the early redemption of bonds. The decrease mainly reflects lower interest rates.

Corporate tax expense was $4,342 million (2001 $6,375 million), representing an effective tax rate of 47% on replacement cost profit before exceptional items. The effective tax rate on the pro forma result, adjusted for special items, was 35% in both years.

Historical cost profit was $6,845 million, including exceptional net gains after tax of $1,043 million and stock holding gains of $1,104 million. The corresponding figures for 2001 were $6,556 million profit, $165 million net gains and $1,900 million losses respectively.

Capital expenditure and acquisitions amounted to $19,111 million, including $5,038 million for the acquisition of Veba. Excluding acquisitions, capital expenditure was $13,322 million, compared with $13,200 million in 2001.

External environment

	2002	2001
BP average liquids realizations ($/barrel)	**22.69**	22.50
Brent oil price ($/barrel)	**25.03**	24.44
BP average natural gas realizations ($/thousand cubic feet)	**2.46**	3.30
Henry Hub gas price ($/thousand cubic feet)	**3.22**	4.26
Global indicator refining margin ($/barrel)	**2.11**	4.06
Chemicals indicator margin ($/tonne)	**102**[a]	109

[a]Provisional.

Operating statistics

	2002	2001
Liquids production (thousand b/d)	**2,018**	1,931
Gas production (million cf/d)	**8,707**	8,632
Total production (thousand boe/d)	**3,519**	3,419
Gas sales (million cf/d)	**21,621**	18,794
Refinery throughputs (thousand b/d)	**3,103**	2,929
Marketing sales (thousand b/d)	**4,180**	3,797
Chemicals production (thousand tonnes)	**26,988**	22,716

Special items ($ million)

	2002	2001
Restructuring, integration and rationalization costs	**774**	761
Impairment charges and asset write-downs	**985**	175
Insurance claim	**(184)**	–
Vacant space provision	**140**	–
Pipeline incident	**62**	–
Litigation	**55**	60
Environmental charges	**46**	–
Other	**22**	–
	1,900	996
Interest – bond redemption charges	**15**	62
Total special items before tax	**1,915**	1,058
Taxation	**(456)**[a]	(375)
Minority shareholders' interest	**(16)**	–
Total special items after tax	**1,443**	683

[a]Includes an adjustment to the North Sea deferred tax liability for the supplementary UK corporation tax as well as tax relief expected on impairments and related restructuring.

Environmental improvement or improved performance? This project proves you can have both – and deliver competitive technological advantage in the process.

BP has been refocusing its strategy for the chemicals business to concentrate on seven core product areas that rely on competitive technological advantage or command significant market positions. The challenge is to do this while maintaining – and beating – our target for reducing greenhouse gas emissions.

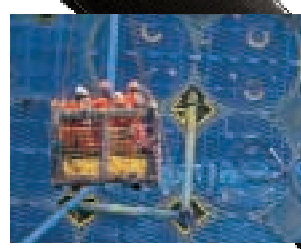
MATRO or, to give its full title, Membrane Application to Recover Olefins, a project completed by our Polyethylene Malaysia team, has demonstrated that we can indeed achieve significant environmental improvement while meeting our strategic priorities.

MATRO uses innovative technology and a smart solution originally discussed during a knowledge-sharing meeting attended by users of BP's licensed proprietary Innovene reaction technology. This should allow the team to reduce by about 30% the carbon dioxide emissions at our Malaysian plant, which produces polyethylene for use in a wide range of applications.

But this is only half the story. Because hydrocarbons are recycled back into the process, our materials costs are also reduced. In fact, with estimated cost savings of $500,000 a year, the project should pay for itself within one year of commissioning.

MATRO offers a great example of how BP's technology and the scale of operations are helping to transform our chemicals business and deliver a distinctive portfolio of products.

A new oil and gas production unit in the Gulf of Mexico has been completed in record time, setting an operating efficiency benchmark for future projects.



BP's stated intention is to concentrate resources on the best investment opportunities and to focus production expertise where it will produce the very best returns.

That's just what we've done at Horn Mountain, BP's Gulf of Mexico deepwater production unit. The production team there has brought the well development into full production only 40 months after the discovery of deepwater reserves – about half the time traditionally required to complete a project of this scale.

Horn Mountain's 26,000-tonne spar, situated in 5,400 feet of water – a record for BP – is expected to produce an estimated 65,000 barrels of oil and 68 million cubic feet of gas daily. This will give BP another key production facility in one of our most important regions, with the prospect of continuing high productivity for many years.

Now, by sharing and applying best-in-class operating practices, the versatile topsides design and streamlined development timeline can be replicated on future projects in the Gulf of Mexico and around the world.

Net cash outflow for the year was $344 million, compared with an inflow of $1,002 million in 2001; lower operating cash flow and higher acquisition spending were partly offset by lower tax payments and higher disposal proceeds. Net cash outflow for capital expenditure and acquisitions, net of disposals, was $10,983 million (2001 $11,604 million).

The group's net debt, that is debt less cash and liquid resources, was $20,273 million at the end of 2002, compared with $19,609 million at the end of the previous year. The ratio of net debt to net debt plus equity was 28%, compared with 29% a year ago. We expect to keep this ratio in the range of 25-35%. In order to maintain the substance of our existing financial framework, the target range has been restated following the adoption of FRS 19. On a reported basis, the percentage was 22% (2001 23%).

In addition to reported debt, BP uses conventional off balance sheet sources of finance such as operating leases and borrowings in associates and joint ventures. The group has access to significant sources of liquidity in the form of committed facilities and other arrangements.

BP has a financial risk management process that addresses the various risk exposures we encounter in the financial markets; these include market risk, credit risk and liquidity risk.

Critical accounting policies

The group's accounts are prepared in accordance with UK Generally Accepted Accounting Practice (UK GAAP). This requires the directors to adopt those accounting policies most appropriate to its particular circumstance for the accounts to give a true and fair view. In preparing the accounts the directors are required to make estimates and assumptions that affect the reported amounts of revenues, expenses, assets and liabilities. Actual outcomes could differ from the estimates and assumptions used.

The directors believe that the critical accounting policies and areas that require the most significant judgements and estimates to be used in the preparation of consolidated accounts are in relation to oil and natural gas reserves; depreciation and amounts provided; impairment; and provisions for decommissioning, environmental liabilities, pension obligations and other post-retirement benefits.

Capital investment ($ million)

	2002	2001
Exploration and Production	**9,266**	8,627
Gas, Power and Renewables	**335**	352
Refining and Marketing	**2,682**	2,386
Chemicals	**810**	1,446
Other businesses and corporate	**228**	389
Capital expenditure	**13,321**	13,200
Acquisitions	**5,790**	924
	19,111	14,124
Disposals	**(6,782)**	(2,903)
Net investment	**12,329**	11,221

BP's creative thinking about a challenging technical problem has delivered a solution that will improve the design of future deepwater drilling projects.

As part of a drive towards greater efficiency, BP is determined to redefine best-in-class in every aspect of its operations, including its deepwater fields. These play a key role in our agenda for future production growth. The potential returns are excellent, although the process of drilling and operating deepwater wells challenges our ingenuity and technology.

A particular issue in deepwater wells is the impact of thermal effects in the wellbore. Historically, there had been little research into such effects, and traditional ways of dealing with this issue were technically challenging.

A smart solution arrived when, following the failure of the Marlin well in the Gulf of Mexico, BP's Houston technology team set out to tackle the problem. They used original thinking and innovative technology to create several ground-breaking well designs that in turn led to new ways of mitigating these effects.

The solution is fast becoming best practice across many other deepwater fields. Once again, BP people have shown their ability to manage technical risks in the most challenging operating environments.

Creditor payment policy and practice

As a general policy, the group encourages long-term relationships founded on trust and mutual advantage. Within this overall policy, individual operating companies are responsible for agreeing terms and conditions for their business transactions and ensuring that suppliers are aware of the terms of payment. These terms are adhered to when payments are made, subject to terms and conditions being met by the supplier.

BP p.l.c. is a holding company with no business activity other than the holding of investments in the group and therefore had no trade creditors at 31 December 2002.

Dividends

The total dividends announced for 2002 were $5,375 million, against $4,935 million in 2001. Dividends per share for 2002 were 24 cents, an increase of 9.1% compared with 2001. In sterling terms, the increase was 1.3%. The board sets the dividend based on a balance of factors. It considers present earnings, together with long-term growth prospects and cash flow. It also considers the group's competitive position and determines the payment, which broadly corresponds to around 60% of sustainable earnings, calculated under standardized assumptions over a run of years.

BP intends to continue the operation of the Dividend Reinvestment Plan (DRIP) for shareholders who wish to receive their dividend in the form of shares rather than cash. The BP Direct Access Plan for US and Canadian investors also includes a dividend reinvestment feature.

Share repurchases

As part of giving a return to shareholders, one of the steps we take from time to time is to repurchase our own shares. During 2002, a total of 100 million shares were repurchased and cancelled at a cost of $750 million. The repurchased shares had a nominal value of $25 million and represented 0.5% of ordinary shares in issue at the end of 2001. At that time the company still had shareholder approval, subject to conditions, for the repurchase of a further 2.1 billion ordinary shares. Since the inception of the share repurchase programme in 2000, 476 million shares have been repurchased and cancelled at a cost of $4.1 billion. BP's present intention is to spend $2 billion on further repurchases of its own shares, subject to market conditions and continuing support at the April 2003 annual general meeting.

Business operating results ($ million)

	2002	2001
Exploration and Production	**12,005**	14,498
Gas, Power and Renewables	**384**	488
Refining and Marketing	**2,081**	4,830
Chemicals	**765**	242

Business performance

Exploration and Production

The result for the year was $12,005 million, compared with $14,498 million in 2001, mainly reflecting the fall in the price of natural gas. We continued to make underlying improvements through a 2.9% growth in production and a reduction in lifting costs.

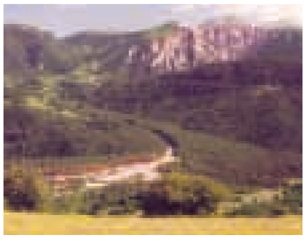
Our strategy is to create a sustainable long-term business, delivering superior returns by building a greater share of large, low-cost oil and gas fields. We maintain a focused approach to choosing the opportunities we want to pursue out of all those available to us. That focus means we have created five new profit centres in which we have a distinctive competitive position: Gulf of Mexico, Trinidad, Azerbaijan, Angola and Asia Pacific.

Our aim is to balance growth and returns by allocating investment to projects with the highest expected returns, ranked globally; by improving operating efficiency; and by selling assets that are not strategic to us and have greater value to others. We have already agreed divestments in 2003 amounting to approximately $3 billion.

In 2002, a number of new fields started producing, the most significant of which were King, King's Peak, Horn Mountain, Aspen and Princess in the deepwater Gulf of Mexico. In Trinidad, production of gas was increased from the existing fields to supply the second liquefied natural gas (LNG) train, which started up in August. In Azerbaijan, the Chirag field contributed steady production. In Angola, production from Girassol built up to its plateau level after starting up at the end of 2001. Production started at the Lan Tay field in Vietnam in November. In our other operations, production from Northstar in Alaska also built up to plateau level, and there was strong performance from Australia and Egypt owing to higher gas sales.

These production increases in 2002 were partly offset by a number of factors, including lower gas demand resulting from warm weather in the UK, OPEC reductions, severe storm patterns in the Gulf of Mexico, the general strike in Venezuela and operational problems in Alaska and the UK.

Exploration successes in 2002 included discoveries in the Gulf of Mexico, Trinidad, Angola and Egypt. The Plutao field is the first ultra-deepwater discovery offshore Angola. We were awarded new licences in the Gulf of Mexico, Norway and Russia. We have led our major competitors in the number of giant discoveries (more than 250 million barrels of oil equivalent) during the past five years. Our reserve replacement ratio in 2002 was 175% – a very competitive result that underpins our long-term growth plans. Reserve replacement has exceeded production for 10 consecutive years.



The BTC pipeline project is helping to create a significant new profit centre for BP as well as the potential for lasting economic and social benefits in the region.

BP is managing the construction of the Baku-Tbilisi-Ceyhan (BTC) pipeline – an ambitious project that will transport oil more than 1,760 kilometres from Baku in Azerbaijan, through Georgia and on to Ceyhan in south-eastern Turkey.

The scale and high profile of this project make it one of the most challenging BP has ever undertaken. A panel of external international experts will publish an independent assessment of how our conduct of the BTC project and our other businesses in the Caspian region matches up to our stated policies and principles.

We have negotiated agreements with the parliaments and governments of all the countries involved. Ongoing consultation with interested parties at local, national and international level is vital. This follows a series of formal environmental and social impact assessments we have already carried out.

Throughout the project we will be doing all we can to minimize the social, political and environmental impact of the pipeline, which is designed to carry one million barrels of oil a day. With our partners we have held discussions with close to 100 stakeholder groups, and run workshops and town hall meetings with local communities along the entire length of the proposed pipeline route.

We believe the pipeline will bring significant benefits both to the region and to BP.

We made significant progress in 2002 in building up our five new material profit centres. Late in 2002, development started at the Atlantis field in the deepwater Gulf of Mexico. Atlantis joined four other fields – Na Kika, Holstein, Mad Dog and Thunder Horse – that are also being developed in the Gulf. Construction of the Mardi Gras pipeline system, to handle the oil and gas production from BP's new fields in the Gulf, continues and is on track.

We made two major natural gas discoveries off the coast of Trinidad in 2002, in Iron Horse and Red Mango #2, taking the total to four new discoveries in three years. We estimate that our undeveloped gas resources in Trinidad now stand at 16 trillion cubic feet. Along with the advantages of scale, improved liquefaction technology has reduced costs in Trinidad by nearly 30%, compared with LNG plants built elsewhere in the 1980s and early 1990s. Continuing technology developments and an increase in plant scale allow us to target a further 25% cost reduction by the end of the decade. This should enable us to compete successfully in new LNG markets.

In an important step towards making possible the export of oil from Azerbaijan and the Caspian region to Turkey's Mediterranean coast, we announced the formation of the Baku-Tbilisi-Ceyhan pipeline company. Initial construction contracts have been awarded, and the pipeline is on schedule for completion in 2005. This is designed to allow a new source of cost-effective and reliable crude oil supply, of up to one million barrels a day by late in the decade, to be brought to the market.

In Angola, Kizomba B was sanctioned and approved, while progress on the development of Kizomba A means it is expected to start up in 2004.

In Asia Pacific, we are continuing to move forward with key natural gas resources, including Tangguh in Indonesia.

Building the five new profit centres requires a high level of capital spending in 2002-04. We intend to invest around $20 billion in these profit centres during 2003-07.

Technical innovations continued to make a substantial contribution to performance, allowing us to enhance the value of our projects. For example, the use of 4D seismic technology improved recovery of reserves to a degree impossible just 10 years ago. Through this technology we estimate some 24,000 barrels a day of additional production capability will become available. New deepwater well designs, already highly successful in fields such as Thunder Horse, Horn Mountain, Marlin, Mad Dog and Atlantis, are improving safety and efficiency.

Our overall safety record improved, with a decline in the number of days away from work case frequency to 0.10 per 200,000 man-hours. This was our best ever and also one of the best performances in our industry. It continues the improvement we have achieved since 1999. We do not intend to rest on this performance but will continue to seek further improvement in our safety record.

In February 2003, we announced an agreement in principle with the Alfa Group and Access-Renova to combine our interests in Russia to create that country's third largest oil and gas business. Once completed, the transaction will create our sixth new upstream profit centre.

Gas, Power and Renewables

The result for 2002 was $384 million, down from $488 million in 2001, owing to a lower contribution from Ruhrgas as a result of its sale and a weaker marketing and trading environment. This was partially offset by a better year-on-year performance in natural gas liquids (NGLs) and increased gas sales volumes.

Gas sales volumes increased 15% in 2002, although margins in the industry were less favourable than in 2001, which had benefited from a period of unusual volatility in North America. Margins improved across our NGLs business through a combination of operating efficiency, lower costs and favourable market conditions. We also achieved more than 20% growth in sales of solar systems and panels, with an overall improvement in total gross margin against increasing competitive pressure.

We have responded to growing demand for cleaner energy by increasing the proportion of gas in our production to 42% from 34% in 1997. Through the gas, power and renewables stream we have established a gas marketing business that is creating and capturing new market opportunities and maximizing the value of the group's gas output.

We are one of the largest marketers of natural gas in North America, with a market share of more than 10%. With the completion of a multi-year transportation, supply and storage arrangement with Kinder Morgan, we now have a leading position in Texas, the largest energy market in the USA. BP is also a new entrant into several liberalizing European markets. We have attained a 10% share of the gas market in Spain and developed marketing activities in Germany, Belgium, Italy and France.

We are becoming a significant supplier to gas markets in the Asia Pacific region. Within the last year, we secured important new markets ahead of developments in our considerable upstream gas resource 'bank'. These include sales to major Chinese customers for liquefied natural gas (LNG) imports through the Guangdong and Fujian import terminals, which will have gas supplied from Australia's North West Shelf (BP 16.6%) and Tangguh, Indonesia (BP 37.2%), respectively.

Globally, the volume of BP's gas production sold as LNG grew by 18% in 2002, with a significant increase resulting from the expansion of our Trinidad and Tobago facilities. This translated into a 5.6% world share in gas produced and converted into LNG. We are progressing plans for new LNG import facilities in key markets in North America, Europe and Asia. In November we launched the *British Trader*, the first of three new leased LNG ships, underpinning significant growth in our trading, shipping and marketing of LNG volumes.

In NGLs, we maintained our position as North America's leading marketer, improving our margin per barrel during 2002. BP holds a 6% share of the global supply of NGLs, with interests in Europe, Asia Pacific and Australia, and also a number of development opportunities around the world.

Customer demand for renewable and alternative energies continued to increase rapidly in key markets. Demand for our solar products rose significantly, consolidating our position as a leading global photovoltaic supplier. In manufacturing, we rationalized our range of solar products by discontinuing the

BP has built a strong partnership with a new customer. This is adding value to the natural gas we market while meeting the customer's broader energy needs competitively.

Frito-Lay, the largest manufacturer and distributor of snack foods in the world, needed an energy services provider that could deliver a customized solution to the complex energy issues facing its North American operation. Crucially, it wanted to work with a partner who mirrored its aspirations and values.

Frito-Lay selected BP as an energy supplier, but soon found we could provide a full range of other products and services, including energy management, energy procurement, energy strategy and consulting, and commodity supplies – primarily natural gas and electricity.

With retail sales in excess of $15 billion for its North American and international divisions, Frito-Lay is a leader in its industry, with progressive and environmental issues high on its agenda. This is an approach BP both understands and shares.

Marketing gas is a highly competitive business. But the ability to broaden the services we offer has added value for our customer while meeting our strategic aim of becoming a partner of choice.

FritoLay

Food for the fun of it

People around the world recognize and trust our brands. Very valuable assets, they are a springboard to growth for our downstream businesses.

BP's challenge is to achieve lowest unit costs while simultaneously increasing market share. Our brands are distinctive and valuable assets that will help us realize these goals.

Amoco, Aral, ARCO, BP and Castrol are all world-class brands, with leading positions in many markets. They help us win new customers and deepen our relationship with the 13 million people we already serve every day.

By focusing investment on this portfolio of brands, supported by innovative technologies, we are achieving improved sales volumes and better profit margins worldwide.

We negotiated an exclusive two-year deal with footballer David Beckham to promote the motorcycle lubricant Castrol Power 1 in the Asia Pacific region – the world's largest motorcycle engine oil market. This initiative has consolidated our leading position in the region, with 80% of targeted consumers identifying Beckham as a positive reason to buy Castrol Power 1.

Meanwhile, in the USA, a focused campaign has made more motorists aware that Amoco fuels, and in particular Amoco Ultimate, are available from BP-branded sites. Sales of this premium fuel continue to outstrip all competitor products. Similar success has been achieved on the US West Coast, where ARCO am/pm has a higher level of brand loyalty than other major oil companies.

Aral is the leading retailer of oil products in Germany. The Aral brand will be extended across all our retail sites there, offering distinctive products and quality service at more than 2,700 stations.

And BP Connect is focused on quality too – providing a superior on-site food service in state-of-the-art convenience stores mainly in the UK and USA. To date, over 486 sites have been completed, with more to come in 2003.

Our world-class brands are building business for BP.

production of thin film modules. We are starting operations at our Tres Cantos plant in Spain, which is designed to produce very high-efficiency photovoltaic systems using Saturn, our proprietary solar technology.

At the Nerefco oil refinery in the Netherlands, jointly owned with ChevronTexaco (BP 69%), our first wind farm was completed and started providing electricity to the refinery and the local grid. It supplies enough clean power for 20,000 homes.

Refining and Marketing

The result for the year was $2,081 million ($4,830 million in 2001). The acquisition of Veba Oil from E.ON, announced in 2001, was completed in 2002, along with the sale of most of Veba's upstream oil and gas assets.

The trading environment was tough, reflecting a halving of worldwide refining margins, together with a further adverse impact from price differentials in BP's crude oil mix, and lower US retail margins. Against this difficult background, we delivered underlying performance improvements in both our refining and marketing businesses, thanks to improved plant availability, increased retail store sales and volume and margin growth in lubricants, while overall operating unit costs were flat. Greater operating efficiency was also reflected in a further improvement in our safety record during the year.

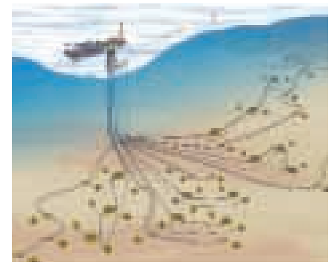
Our strategy is to grow through investment focused on key assets and market positions. In each of our four areas of business – refining, retail, lubricants and business-to-business marketing – we continue to aim for greater operational efficiency. At the same time, we also seek to improve the quality of our assets. This was enhanced in 2002 thanks to the continuing integration of Veba's marketing and refining operations.

We are one of the leading refiners and marketers of gasoline and hydrocarbon products in the USA, where we own and operate five large refineries with extensive clean-fuel capability. In Europe we own or participate in 13 refineries, 10 of which are operated by BP, which substantially expand our capacity to market cleaner fuels. Investment in our refineries is focused on developing the capability to produce cleaner fuels and on enhancing the quality of the products we offer customers. By the end of 2002, we were marketing cleaner fuels in 119 cities worldwide.

In our retail business, competitive pressures intensified in some markets, especially the USA. In order to achieve above-average growth and take full advantage of our best assets, we invested in our new Connect convenience stores, expanding our presence mainly in core metropolitan markets. In 2002, we opened 147 new BP Connect convenience sites, mainly in the USA and UK, and rebranded 4,611 stations worldwide with the BP helios logo and colours.

At the end of 2002, there were about 26,000 BP, Amoco and ARCO branded service stations worldwide and 3,200 Aral branded stations in Europe. In due course we will rebrand all our stations in Germany as Aral.

Retail sales grew 7% last year in stores that were also operating in 2001, a similar rate to the previous year. Retail fuel volumes grew by 10%, including the effect of the Veba acquisition.



Pursuing an ambitious five-year agenda for exploration and production, BP is focusing more than 50% of its upstream investment on five material profit centres around the world.

Angola is one of those five. As one of the largest businesses operating in the country, BP is set to play an important role in delivering the resources that will support recovery within the new context of reconstruction and reform after 27 years of civil war.

The country's enormous potential makes it of key interest to us. Our Angola team has built a strong foundation for growth through both exploration and development. Technical skills developed in similar deepwater basins around the world have been used to great effect. Today, BP is unique in participating in the four major deepwater blocks in the country.

2002 has seen real progress, with Girassol, Angola's first deepwater project, delivering a full year's production. Several more projects are under construction, while new discoveries continue to be made.

All this is proof of our belief that new areas such as Angola will not only renew BP in the medium term, but offer further, as yet unrealized, opportunities in the longer term.

BP is delivering its commitment to provide a better environment through technological innovation and tailored offers for customers.

For all of us, particularly those living or working in major cities, air quality is a pressing issue. So an innovative low-emissions initiative pioneered by BP that has produced dramatic and immediate reductions in emissions of pollutants is very good news indeed.

System City, launched in December 2001, is aimed specifically at commercial fleet operators – typically bus or road haulage companies. The initiative encourages customers to use two new products together: Aspira, a revolutionary ultra-low sulphur diesel emulsion fuel, and Vanellus C8 Ultima, an ultra-high performance synthetic lubricant.

For customers who have made the switch, including Arriva buses in London, UK, the results have been impressive. Smoke has been cut by 65%, smog-promoting nitrous oxide by 15%, asthma-aggravating particulate matter by 35% and carbon dioxide by up to 12%. And these reductions have been achieved without extra capital investment. Old or new, any bus or truck can be switched to run on System City with no modifications at all.

Our leading global position in the lubricants business is based on powerful brands such as Castrol and BP, and continued technological improvements. We continued to invest in advertising and sales promotion. This allowed us to achieve volume growth in 2002, despite a decline of 0.5% on average for the market, with an expanding margin. In business-to-business marketing we offered our customers a range of innovative high-value services and cleaner fuels, and gained a bigger market share for businesses such as Air BP.

A €377 million sale of retail and refinery assets in Germany and central Europe announced in February 2003 will complete the divestments required by the Veba acquisition regulator.

Chemicals

The result was $765 million, an improvement of $523 million compared with 2001. Despite a similarly adverse trading environment throughout the year, this was an increase of 216% compared with 2001. This performance was achieved through capacity growth from both capital investment and acquisitions, and significant reductions in fixed costs.

Underpinning this transformation in performance were better safety and reliability in all our manufacturing. For example, at Köln, Germany, our biggest site, our performance in both reliability and utilization was in the top quartile for the industry. The site safety record saw a second year of significant improvement, without a single day away from work case during a year in which more than 8.5 million man-hours were worked.

During the year we completely reviewed our strategy, and are now focusing on seven core products for which we have leading technologies and market positions. We have opened new world-class plants and shut some inefficient ones, for example, switching high-density polyethylene production to a world-scale plant in Houston from the older and smaller Deer Park plant elsewhere in Texas. This has enabled us to continue improving the quality of our portfolio. We also made some disposals, including the plastic fabrications business and one of the Burmah Castrol chemicals businesses. By early 2003, we had agreed the sale of the remaining Burmah Castrol chemicals businesses.

We continue to improve the environmental impact of our operations as we introduce new capacity. For example, at our Chocolate Bayou olefins complex in Texas we are planning to increase ethylene production by 20%. Yet the use of new technology at the site, where the expanded plant is expected to start operating in late 2005, should reduce emissions of nitrogen oxides from the olefins plants by up to 90%.

In addition to improving the performance of our own operations, we have also worked closely with suppliers to ensure that our products minimize energy use and waste while meeting customers' needs, as in the manufacture of speciality acrylic fibres. A unique partnership between BP, process suppliers, transport providers and key customers in Mexico and Italy has generated new methods of purifying and segregating acrylonitrile, which results in less waste and lower emissions at the point of fibre manufacture.

BP is now the world's third largest petrochemicals company in terms of capacity, and manufactures and markets more than 26 million tonnes of products each year.

In one of the world's largest and fastest-growing economies, our ability to share experience and expertise across cultural boundaries makes BP a natural business partner.

The Chinese economy, currently worth $1.1 trillion, is growing at 8% a year. China's need for energy is enormous and it is committed to meet this need in an environmentally sustainable way. BP is playing an active role in fuelling this transformation.

Our chemicals strategy, focusing on seven core products in markets that offer significant market share, is exemplified in our Zhuhai plant. Here innovative thinking and cutting-edge technology will revolutionize production of purified terephthalic acid (PTA), used to make plastic bottles and polyester fibres and yarns. Working together, BP research, development, engineering and design teams have built a brand-new PTA plant in record time, achieving a 44% reduction in equipment requirements and targeting a reduction of 30% in site waste.

In Shanghai, BP has secured a joint venture with state-owned Sinopec and the Shanghai Petrochemicals Company to build Asia's largest ethylene cracker. The plant will be sited on partially reclaimed land 50 kilometres south of Shanghai, one of China's fastest-growing cities. When complete, the $2.7-billion SECCO project should meet rigorous environmental standards. Its output will help satisfy China's growing need for products such as plastics for irrigation pipes, fabrics and fibres for clothing and other core consumer products.

The Chinese government aims to increase the proportion of natural gas in its energy mix from 2% to 8% by 2010 – an ambitious move that would have substantial environmental benefits.

A leader in LNG production, BP was delighted to be chosen as sole foreign partner in the construction of China's first LNG import facility at Guangdong. In addition, BP is involved in the supply of LNG to Chinese customers via Guangdong and China's second LNG import terminal at Fujian. These developments support our strategy of maximizing the value of our gas.

BP's downstream operations in China are thriving. We are a major importer and wholesaler of LPG – used in transport, retail, catering and manufacturing – into the developing markets of eastern and southern China. We have built and now manage our own LPG import terminal at Ningbo. Both activities show our focus on serving high-value markets.

Our strategy of investing for growth in new markets is spearheaded through a joint venture with PetroChina. Together we are launching 300 dual-branded service stations that will strengthen our market position in the country's potentially lucrative retail sector. In the long term our intention is to have a material share of the Chinese retail market.

Whether in chemicals, gas or retail markets, China offers huge potential for future growth to BP.

Environmental and social performance

We believe our business should benefit society and the environment. We strive to understand all impacts of our activities, positive and negative, and with this knowledge seek opportunities that maximize value for all our stakeholders.

Our five business policies guide our actions. These cover health, safety and environment; employees; relationships; ethical conduct; and finance. They inform every decision made by every employee. Each individual in the company is required to comply; our partners, suppliers and contractors are encouraged to adopt them. We believe there is no trade-off between high standards and high performance.

Dealing with risks

Doing business in environmentally and socially sensitive areas demands effective processes and controls. Our risk management processes analyse a range of impacts, whether local, national or global, including the effects our operations may have on specific communities.

Accountability for managing our social and environmental impact is written into business managers' individual performance contracts. These contain specific objectives and firm deadlines for delivery during the year.

Health, safety and environmental performance

Increasing standards of safety at work is of the highest priority and is essential to the wellbeing of our workforce. Every facility aims to apply health, safety and environmental systems rigorously. These are implemented by all staff and verified through regular and extensive audits and assurance processes. In 2002, we more than met our target of reducing the number of accidents that cause injury (a 23% improvement compared with 2001), giving us again one of the best safety records in the industry. Safety audits, leadership training and formal incident investigations contributed to this improvement.

Although the total number of major incidents declined, we regret to report three employee and 10 contractor deaths at work in 2002, compared with 16 deaths in 2001. We are determined to continue to make progress towards our goal of zero fatalities. All executives have explicit safety improvement objectives that form part of their remuneration. One key objective for 2002, to establish BP's new 'Golden Rules of Safety', has been completed across all our businesses.

Oil spills at sea or on land remain a key environmental risk for our industry. Our independently certified environmental management systems drive continuous performance improvement on the number of oil spills (of more than one barrel), which reduced from 810 in 2001 to 742 last year (excluding Veba operations). Our own shipping fleet transports significant volumes of oil, gas and chemicals around the world. We are undertaking a fleet replacement programme that should see 16 modern double-hulled vessels delivered by the end of 2003, with a further 19 confirmed for 2004 onwards. Where we charter additional vessels, they are vetted prior to use to ensure they meet our rigorous operational standards.

In 2002, we announced a new approach on climate change that received favourable reactions from many expert organizations worldwide. Having already lowered our emissions by 10%, we are now committed, through combinations of energy efficiency, flaring reductions and lower-carbon products, to maintain our net emissions at these reduced levels over the next decade. We are pleased to report that, on a like-for-like basis to take into account the effect of acquisitions and divestments, our net emissions reduction for 2002 was 0.3 million tonnes. This is in line with our new target. This result was primarily achieved through substantial cuts in flaring and venting, generating over 1.8 million tonnes of sustainable emission reductions, offsetting organic growth of 1.5 million tonnes. Including acquisitions and divestments, of which Veba contributed 4.1 million tonnes, greenhouse gas emissions of the group were 82.4 million tonnes for the year.

BP recognizes the need to protect and conserve the biodiversity of our planet. A review of operations following our undertaking prior to the AGM last year confirmed that, during 2002, no decisions were made to explore or develop in areas designated by the World Conservation Union (IUCN) as conservation management categories I-IV. Descriptions of our risk assessments supporting future decisions will be reported in the *BP Environmental and Social Review 2002 (see page 40)*. We are working closely with the IUCN to develop a consistent approach to the identification and designation of protected areas, which we will respect wherever we operate. In many locations, our biodiversity action plans have stimulated much local stakeholder engagement and innovative solutions to preserve natural habitats for flora and fauna.

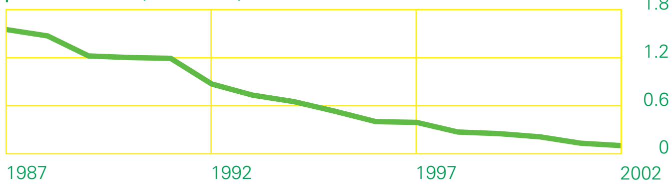
Employees

As a global group with operations in many of the world's developing countries, in 2002 we gave the employment and development of local staff an important focus. Programmes in countries such as China, Vietnam, Trinidad and Angola have ensured that our workforce is increasingly composed of locally based employees. The experience of both local and expatriate staff is helping each develop skills that can contribute to the successful future of our operations and the community.

With a global workforce, our leadership should reflect the diversity within our organization and recruitment intake. Through continuous review of our development processes, we again increased the proportion of our senior leaders who are female or of non-UK or non-US nationality.

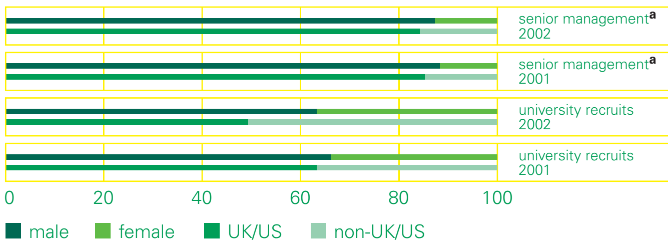
Our First Level Leaders programme, piloted in 2001 and successfully introduced in 2002, is an important step in

Long-term improvement in safety performance (DAFWCF)[a] 1987-2002



[a]Days away from work case frequency (DAFWCF) is the annual frequency (per 200,000 hours) of injuries or illnesses that result in a person (employee or contractor) being unable to work for a day (shift) or more. Excludes data for Veba employees and contractors and Castrol contractors. Data before 1992 excludes contractors.

Employee profile by gender and nationality (%)



[a]Senior management includes the top 622 positions in BP.

ensuring that this trend continues. Developing the skills of front-line leaders within a supportive network of colleagues, it is run in 29 countries. More than 4,500 people attended the programme in 2002, with similar numbers expected in 2003.

We have expanded employee ownership schemes, including 17 new countries for our ShareMatch scheme through which we match BP shares bought by employees. We now have employee share plans in 77 countries and have received several external awards for them.

It is BP's policy to ensure equal opportunity in recruitment, promotion, career development, training and reward for all employees, including those with disabilities. All applicants and employees are assessed against clear criteria related to job requirements. Where existing employees become disabled, it is BP's policy to provide continuing employment and training wherever practicable.

We use a range of media to communicate systematically with employees, including a global magazine, an intranet, e-mails to groups of staff selected by seniority or region and, most importantly, face-to-face communication. Team meetings are the core of our consultation with employees worldwide, complemented by formal consultation processes through works councils in parts of Europe. All these media, along with training programmes, enhance awareness of financial and economic factors affecting BP's performance.

Relationships

We believe that long-term relationships, founded on trust and mutual advantage, are vital to BP's business success. Our business operations involve us in many relationships with investors, non-governmental organizations (NGOs), customers, suppliers, communities, governments and employees.

During the year, we continued with our stakeholder consultation process in Azerbaijan, Georgia and Turkey in order to understand the concerns and aspirations of people affected by our proposed investments. Their feedback is vital to the success of our business in the Caspian region and a number of their suggestions and recommended actions have already been implemented.

In dealing with broader issues that affect our business, we look to join partnerships, coalitions and alliances. For example, in 2002 we joined the Global Business Coalition on HIV/AIDS, a partnership between governments, companies and NGOs. It aims to tackle the growing social, economic and political impacts of this disease. We are also involved in the World Bank's Extractive Industries Review and the UN Global Compact.

At the 2002 World Summit for Sustainable Development, a BP delegation took part in discussions concerning the use of energy in society. It was agreed that secure and affordable energy services were needed to support social and economic development in poorer developing countries without producing environmental degradation. We are now exploring how we can participate in various initiatives and partnerships that emerged from the summit.

We continue to confront the challenges of implementing international standards of human rights. In 2002, we engaged with a wide variety of NGOs and civil society organizations that on a global or local level are devoted to the promotion and protection of human rights. We have further contributed to the progress of the Voluntary Principles on Security and Human Rights, an international initiative for companies in the extractive sector, which is now supported by some governments as well as by leading human rights NGOs.

Ethical conduct

We expect our staff to act according to the highest standards of ethical behaviour. This is reinforced through an annual process and through policy development, training and actions that uphold our standards, including disciplinary measures. During 2002, 132 people were dismissed for unethical behaviour, including fraud, conflict of interest and internet abuse.

In 2002, we strengthened our anti-corruption stance by prohibiting facilitation payments and by identifying and correcting areas of non-compliance. We decided to stop making corporate political contributions anywhere in the world from April 2002. During the first quarter of the year, group companies made contributions totalling $220,100 to North American political parties and candidates; since then, we have made no further corporate political contributions. In 2002, we again made no donations to any UK or other EU political parties or organizations.

We increased the emphasis on ethical behaviour across the group. Eight regional ethics committees were established and more than 500 ethics workshops run worldwide. Two on-line ethics modules for employees were introduced and local case studies developed to share best practice. We are making it easier for staff to raise in confidence their concerns about any aspect of the business, including safety, the environment and finance. This process, starting in 2003, is being overseen by ombudsmen in each region.

Every year, those in positions of responsibility are asked to attest that their personal behaviour and the actions of their teams comply with our ethical conduct policy. We significantly enhanced this process last year to encourage open discussion and sharing of ethical issues, which we believe will contribute to continuous improvement in the way we do business.

Summary group income statement

For the year ended 31 December

	Note	2002	2001
		$ million	
Group turnover		**178,721**	174,218
Group replacement cost operating profit	3	**9,284**	14,824
Share of profits of joint ventures		**346**	443
Share of profits of associated undertakings		**616**	760
Total replacement cost operating profit	4	**10,246**	16,027
Profit (loss) on sale of businesses or termination of operations	5	**(33)**	(68)
Profit (loss) on sale of fixed assets	5	**1,201**	603
Replacement cost profit before interest and tax		**11,414**	16,562
Stock holding gains (losses)		**1,129**	(1,900)
Historical cost profit before interest and tax		**12,543**	14,662
Interest expense		**1,279**	1,670
Profit before taxation		**11,264**	12,992
Taxation		**4,342**	6,375
Profit after taxation		**6,922**	6,617
Minority shareholders' interest (MSI)		**77**	61
Profit for the year		**6,845**	6,556
Distribution to shareholders	6	**5,375**	4,935
Retained profit for the year		**1,470**	1,621
Earnings per ordinary share – cents			
Basic	7	**30.55**	29.21
Diluted	7	**30.41**	29.04

Replacement cost results

	Note	2002	2001
Historical cost profit for the year		**6,845**	6,556
Stock holding (gains) losses (net of MSI)		**(1,104)**	1,900
Replacement cost profit for the year	2	**5,741**	8,456
Exceptional items (net of tax)	5	**(1,043)**	(165)
Replacement cost profit before exceptional items		**4,698**	8,291
Earnings per ordinary share – cents			
On replacement cost profit before exceptional items	7	**20.97**	36.95

Directors' emoluments

Total emoluments received by BP directors were $27,814,000 ($33,767,000).

The summary financial statement on pages 1 to 26 and 28 to 41 was approved by a duly appointed and authorized committee of the board of directors on 11 February 2003 and signed on its behalf by:

Peter Sutherland, Chairman

The Lord Browne of Madingley, Group Chief Executive

Summary group balance sheet
At 31 December

	2002	2001
		$ million
Fixed assets		
Intangible assets	**15,566**	16,489
Tangible assets	**87,682**	77,410
Investments	**10,811**	11,963
	114,059	105,862
Current assets		
Stocks	**10,181**	7,631
Debtors	**33,150**	26,669
Investments	**215**	450
Cash at bank and in hand	**1,520**	1,358
	45,066	36,108
Creditors – amounts falling due within one year		
Finance debt	**10,086**	9,090
Other creditors	**36,215**	28,524
Net current liabilities	**(1,235)**	(1,506)
Total assets less current liabilities	**112,824**	104,356
Creditors – amounts falling due after more than one year		
Finance debt	**11,922**	12,327
Other creditors	**3,455**	3,086
Provisions for liabilities and charges		
Deferred taxation	**13,514**	11,702
Other provisions	**13,886**	11,482
Net assets	**70,047**	65,759
Minority shareholders' interest – equity	**638**	598
BP shareholders' interest	**69,409**	65,161
Represented by		
Capital and reserves		
Called up share capital	**5,616**	5,629
Reserves	**63,793**	59,532
	69,409	65,161

Movements in BP shareholders' interest

At 31 December 2001	74,367
Prior year adjustment – change in accounting policy (see Note 1)	(9,206)
As restated	65,161
Profit for the year	6,845
Distribution to shareholders	(5,375)
Currency translation differences (net of tax)	3,333
Issue of ordinary share capital for employee share schemes	195
Repurchase of ordinary share capital	(750)
At 31 December 2002	**69,409**

Summary group cash flow statement

For the year ended 31 December

		$ million
	2002	2001
Net cash inflow from operating activities[a]	**19,342**	22,409
Dividends from joint ventures	**198**	104
Dividends from associated undertakings	**368**	528
Net cash outflow from servicing of finance and returns on investments	**(911)**	(948)
Tax paid	**(3,094)**	(4,660)
Net cash outflow for capital expenditure and financial investment	**(9,646)**	(9,849)
Net cash outflow for acquisitions and disposals	**(1,337)**	(1,755)
Equity dividends paid	**(5,264)**	(4,827)
Net cash (outflow) inflow	**(344)**	1,002
Financing	**(181)**	972
Management of liquid resources	**(220)**	(211)
Increase in cash	**57**	241
	(344)	1,002

[a] Reconciliation of historical cost profit before interest and tax to net cash inflow from operating activities

		$ million
	2002	2001
Historical cost profit before interest and tax	**12,543**	14,662
Depreciation and amounts provided	**10,401**	8,858
Exploration expenditure written off	**385**	238
Share of profits of joint ventures and associated undertakings	**(966)**	(1,194)
Interest and other income	**(358)**	(478)
(Profit) loss on sale of fixed assets and businesses or termination of operations	**(1,166)**	(537)
(Increase) decrease in working capital and other items	**(1,497)**	860
Net cash inflow from operating activities	**19,342**	22,409

Notes

1 Presentation of the accounts

These summarized financial statements represent an abridged version of the financial statements in *Annual Accounts 2002*. For 2002, the group has changed the method of accounting for deferred taxation to comply with a new UK accounting standard. Comparative figures have been restated to reflect this change in accounting policy, and also to reflect the transfer of the solar, renewables and alternative fuels activities from Other businesses and corporate to Gas, Power and Renewables.

2 Replacement cost profit

Replacement cost profits reflect the current cost of supplies. The replacement cost profit is arrived at by excluding stock holding gains and losses from the historical cost profit.

3 Other income

	$ million	
	2002	2001
Group replacement cost operating profit includes:		
Income from other fixed asset investments	**139**	208
Other interest and miscellaneous income	**502**	486

4 Analysis of total replacement cost operating profit

	$ million	
	2002	2001
By business		
Exploration and Production	**9,206**	12,361
Gas, Power and Renewables	**354**	488
Refining and Marketing	**872**	3,573
Chemicals	**515**	128
Other businesses and corporate	**(701)**	(523)
	10,246	16,027

	$ million	
	2002	2001
By geographical area		
UK	**1,696**	2,668
Rest of Europe	**1,703**	1,814
USA	**2,890**	6,941
Rest of World	**3,957**	4,604
	10,246	16,027

5 Exceptional items

	$ million	
	2002	2001
Exceptional items comprise profit (loss) on sale of fixed assets and businesses or termination of operations as follows:		
Profit on sale of businesses or termination of operations – Group	**195**	182
Loss on sale of businesses or termination of operations – Group	**(228)**	(250)
	(33)	(68)
Profit on sale of fixed assets – Group	**2,736**	948
– Associated undertakings	**2**	–
Loss on sale of fixed assets – Group	**(1,537)**	(343)
– Associated undertakings	**–**	(2)
Exceptional items	**1,168**	535
Taxation credit (charge):		
Sale of businesses or termination of operations	**45**	(100)
Sale of fixed assets	**(170)**	(270)
Exceptional items (net of tax)	**1,043**	165

Sale of businesses or termination of operations The profit on the sale of businesses in 2002 relates mainly to the disposal of the group's retail network in Cyprus and the UK contract energy management business. For 2001 the profit relates to the sale of the group's interest in Vysis.

The loss on sale of businesses or termination of operations for 2002 represents the loss on disposal of the plastic fabrications business, the loss on disposal of the former Burmah Castrol speciality chemicals business Fosroc Construction, the loss on withdrawal from solar thin film manufacturing and the provision for the loss on divestment of the former Burmah Castrol speciality chemicals businesses Sericol and Fosroc Mining. The loss during 2001 arose principally from the sale of the group's Carbon Fibers business and the write-off of assets following the closure or exit from certain chemicals activities.

Sale of fixed assets The major part of the profit on the sale of fixed assets during 2002 arises from the divestment of the group's shareholding in Ruhrgas. The other significant elements of the profit for the year are the gain on the redemption of certain preferred limited partnership interests BP retained following the Altura Energy common interest disposal in 2000 in exchange for BP loan notes held by the partnership, the profit on the sale of the group's interest in the Colonial pipeline in the USA and the profit on the sale of a US downstream electronic payment system. For 2001 the profit on the sale of fixed assets includes the profit from the divestment of the refineries at Mandan, North Dakota, and Salt Lake City, Utah; the group's interest in the Alliance and certain other pipeline systems in the USA; and BP's interest in the Kashagan discovery in Kazakhstan.

The major element of the loss on sale of fixed assets relates to provisions for losses on sale of exploration and production properties in the UK and USA announced in early 2003. For 2001 the loss on sale of fixed assets arose from a number of transactions.

6 Distribution to shareholders

	pence per share		cents per share		$ million	
	2002	2001	**2002**	2001	**2002**	2001
Preference dividends (non-equity)					**2**	2
Dividends per ordinary share: First quarterly	**4.051**	3.665	**5.75**	5.25	**1,290**	1,178
Second quarterly	**3.875**	3.911	**6.00**	5.50	**1,346**	1,235
Third quarterly	**3.897**	3.805	**6.00**	5.50	**1,340**	1,232
Fourth quarterly	**3.815**	4.055	**6.25**	5.75	**1,397**	1,288
	15.638	15.436	**24.00**	22.00	**5,375**	4,935

7 Earnings per ordinary share

The calculation of basic earnings per ordinary share is based on the profit attributable to ordinary shareholders, i.e. profit for the year less preference dividends, related to the weighted average number of ordinary shares in issue during the year. The profit attributable to ordinary shareholders is $6,843 million ($6,554 million). The average number of shares outstanding excludes the shares held by the Employee Share Ownership Plans.

The calculation of diluted earnings per share is based on profit attributable to ordinary shareholders as for basic earnings per share. However, the number of shares outstanding is adjusted to show the potential dilution if employee share options are converted into ordinary shares.

In addition to earnings per share based on the historical cost profit for the year, a further measure, based on replacement cost profit before exceptional items, is provided as it is considered that this measure gives an indication of underlying performance.

8 Capital expenditure and acquisitions

	$ million	
	2002	2001
By business		
Exploration and Production	**9,699**	8,861
Gas, Power and Renewables	**408**	492
Refining and Marketing	**7,753**	2,415
Chemicals	**823**	1,926
Other businesses and corporate	**428**	430
	19,111	14,124

	$ million	
	2002	2001
By geographical area		
UK	**1,637**	2,128
Rest of Europe	**6,556**	1,787
USA	**6,095**	6,160
Rest of World	**4,823**	4,049
	19,111	14,124

Independent auditors' statement

To the Members of BP p.l.c.

We have examined the group's summary financial statement for the year ended 31 December 2002. This report is made solely to the company's members, as a body, in accordance with section 251 of the Companies Act 1985. To the fullest extent required by law, we do not accept or assume responsibility to anyone other than the company and the company's members as a body, for our audit work, for this report or for the opinions we have formed.

Respective responsibilities of directors and auditors

The directors are responsible for preparing *Annual Report 2002* in accordance with applicable law. Our responsibility is to report to you our opinion on the consistency of the summary financial statement within *Annual Report 2002* with the full annual accounts, Directors' Report and Directors' Remuneration Report and its compliance with the relevant requirements of section 251 of the Companies Act 1985 and the regulations made thereunder. We also read the other information contained in *Annual Report 2002* and consider the implications for our report if we become aware of any apparent misstatements or material inconsistencies with the summary financial statement.

Basis of opinion

We conducted our work in accordance with Bulletin 1999/6 'The auditors' statement on the summary financial statement' issued by the Auditing Practices Board for use in the United Kingdom.

Opinion

In our opinion the summary financial statement is consistent with the full annual accounts, Directors' Report and Directors' Remuneration Report of BP p.l.c. for the year ended 31 December 2002 and complies with the applicable requirements of section 251 of the Companies Act 1985, and the regulations made thereunder.

Ernst & Young LLP
Registered Auditor
London
11 February 2003

The auditors have issued an unqualified audit report on the annual accounts containing no statement under section 237 (2) or section 237 (3) of the Companies Act 1985.

United States accounting principles

The following is a summary of adjustments to profit for the year and to BP shareholders' interest which would be required if generally accepted accounting principles in the USA (US GAAP) had been applied instead of those generally accepted in the United Kingdom (UK GAAP). The results are stated using the first-in first-out method of stock valuation.

		$ million
	2002	2001
Profit for the year	**6,845**	6,556
Deferred taxation/business combinations	**(315)**	(815)
Provisions	**8**	(182)
Impairment	**–**	(911)
Sale and leaseback	**24**	(36)
Goodwill	**1,302**	60
Derivative financial instruments	**540**	(313)
Gain arising on asset exchange	**(18)**	157
Other	**11**	10
Profit for the year before cumulative effect of accounting change as adjusted to accord with US GAAP	**8,397**	4,526
Cumulative effect of accounting change:		
Derivative financial instruments	**–**	(362)
Profit for the year as adjusted to accord with US GAAP	**8,397**	4,164
Dividend requirement on preference shares	**2**	2
Profit for the year applicable to ordinary shares as adjusted to accord with US GAAP	**8,395**	4,162
Per ordinary share – cents		
Basic – before cumulative effect of accounting change	**37.48**	20.16
Cumulative effect of accounting change	**–**	(1.61)
	37.48	18.55
Diluted – before cumulative effect of accounting change	**37.30**	20.04
Cumulative effect of accounting change	**–**	(1.60)
	37.30	18.44
Per American depositary share[a] – cents		
Basic – before cumulative effect of accounting change	**224.88**	120.96
Cumulative effect of accounting change	**–**	(9.66)
	224.88	111.30
Diluted – before cumulative effect of accounting change	**223.80**	120.24
Cumulative effect of accounting change	**–**	(9.60)
	223.80	110.64

		$ million
	2002	2001
BP shareholders' interest	**69,409**	65,161
Deferred taxation/business combinations	**(78)**	243
Provisions	**(1,088)**	(1,054)
Sale and leaseback	**(106)**	(134)
Goodwill	**(84)**	(1,414)
Derivative financial instruments	**(135)**	(675)
Gain arising on asset exchange	**142**	157
Ordinary shares held for future awards to employees	**(159)**	(266)
Dividends	**1,398**	1,288
Investments	**34**	(2)
Additional minimum pension liability	**(2,286)**	(942)
Other	**(48)**	(40)
BP shareholders' interest as adjusted to accord with US GAAP	**66,999**	62,322

[a] One American depositary share is equivalent to six 25 cent ordinary shares.

Corporate governance

The board's governance policies regulate its relationship with shareholders, the conduct of board affairs and its relationship with the group chief executive. The policies recognize that the board has a separate and unique role as the link in the chain of authority between the shareholders and the group chief executive. In addition, they acknowledge the dual role played by the group chief executive and executive directors as both members of the board and leaders of the executive management. The policies therefore require a majority of the board to be composed of non-executive directors and delegate all aspects of the relationship between the board and the group chief executive to the non-executive directors. The policies also require the chairman and deputy chairman to be non-executive directors; throughout 2002 the posts were held by Mr Sutherland and Sir Ian Prosser respectively. Sir Ian Prosser acts as the senior independent non-executive director as required by the Combined Code on Corporate Governance. Finally, the company secretary reports to the non-executive chairman and is not part of the executive management.

Relationship with shareholders

The policies emphasize the importance of the relationship between the board and the shareholders. In them the board acknowledges that its role is to represent and promote the interests of shareholders and that it is accountable to shareholders for the performance and activities of the group (including, for example, the system of internal control and the review of its effectiveness). The board is required to be proactive in obtaining an understanding of shareholder preferences and to evaluate systematically the economic, social, environmental and ethical matters that may influence or affect the interests of its shareholders. These interests are represented and promoted by the board through exercising its policy-making and monitoring functions. As a result, shareholder interests lie at the heart of the goals established by the board for the company.

The board is accountable to shareholders in a variety of ways. Directors are required to stand for re-election every three years to ensure that shareholders have a regular opportunity to reassess the composition of the board. New directors are subject to election at the first opportunity following their appointment. Names submitted to shareholders for election in 2002 were accompanied by biographical details.

The board makes use of a number of formal channels of communication to account to shareholders for the performance of the company. These include the Annual Report and Accounts, the Annual Report on Form 20-F filed with the US Securities and Exchange Commission, quarterly announcements made through stock exchanges on which BP shares are listed and the annual general meeting of shareholders. Given the size and geographical diversity of BP's shareholder base, the opportunities for shareholder interaction at the annual general meeting are limited. However, the chairman and all board committee chairmen were present at the 2002 annual general meeting to answer questions. All proxy votes at shareholder meetings are counted since votes on all matters except procedural issues are taken by way of a poll. BP has also pioneered the use of electronic communications to facilitate the exercise of shareholder control rights. Presentations given at appropriate intervals to representatives of the investment community are available simultaneously to all shareholders by live internet broadcast or open conference call.

Board process

The board has laid down rules for its own activities in a board process policy that covers the conduct of members at meetings; the cycle of board activities and the setting of agendas; the provision of information to the board; board officers and their roles; board committees, their tasks and composition; qualifications for board membership and the process of the Nomination Committee; the remuneration of non-executive directors; the appointment and role of the company secretary; the process for directors to obtain independent advice and the assessment of the board's performance. The board process policy places responsibility for implementation of this policy, including training of directors, on the chairman.

The policy recognizes that the board's capacity, as a group, is limited. The board therefore reserves to itself the making of broad policy decisions, delegating more detailed considerations involved in meeting its stated requirements either to board committees and officers (in the case of its own processes) or to the group chief executive (in the case of the management of the company's business activity). The policy allocates the tasks of monitoring executive actions and assessing reward to the following committees:

- *Chairman's Committee (all non-executive directors)* – to review the structure and effectiveness of the business organization; succession planning for the executive directors and the most senior executives; and to assess the overall performance of the group chief executive. The committee met four times during 2002.
- *Audit Committee (4-6 non-executive directors)* – to monitor all reporting, accounting, control and financial aspects of the executive management's activities. This includes systematic monitoring and obtaining assurance that the legally required standards of disclosure are being fully and fairly observed and that the executive limitations relating to financial matters are being observed. The committee keeps under review the scope and results of audit work, its cost-effectiveness and the independence and objectivity of the auditors. It requires the auditors to rotate their lead audit partner every five years and reviews non-audit assignments. Aside from its monitoring of external audit work, the committee considers the internal audit programme. The auditors' lead partner and the BP general auditor (head of internal audit) attend each meeting at the request of the committee chairman. The committee met 10 times during 2002.
- *Ethics and Environment Assurance Committee (4-6 non-executive directors)* – to monitor the non-financial aspects of the executive management's activities. The auditors' lead partner and the BP general auditor (head of internal audit) attend each meeting at the request of the committee chairman. The committee met four times during 2002.
- *Remuneration Committee (4-6 non-executive directors)* – to determine performance contracts, targets and the structure of the rewards for the group chief executive and the executive directors and to monitor the policies being applied in remunerating other senior executives. The committee met five times during 2002. The directors' remuneration report appears on pages 30 to 39.
- *Nomination Committee (the chairman, group chief executive and three non-executive directors selected from time to time as required)* – to identify, evaluate and recommend candidates for appointment or reappointment as directors and as company secretary. The committee met once during 2002.

The qualification for board membership includes a requirement that non-executive directors be free from any relationship with the executive management of the company that could materially interfere with the exercise of their independent judgement. In the board's view, all non-executive directors fulfil this requirement. The board met nine times during 2002, six times in the UK, twice in the USA and once in Europe for a two-day strategy discussion. Committee meetings are held in conjunction with board meetings whenever possible.

In carrying out its work, the board has to exercise judgement about how best to further the interests of shareholders. Given the uncertainties inherent in the future of business activity, the board seeks to maximize the expected value of the shareholders' interest in the company, not to eliminate the possibility of any adverse outcomes for shareholders.

Board/Executive relationship

The board/executive relationship policy sets out how the board delegates authority to the group chief executive and the extent of that authority. In its goals policy, the board states the long-term outcome it expects the group chief executive to deliver. The restrictions on the manner in which the group chief executive may achieve the required results are set out in the executive limitations policy, which addresses ethics, health, safety, the environment, financial distress, internal control, risk preferences, treatment of employees and political considerations. On all these matters, the board's role is to set general policy and to monitor the implementation of that policy by the group chief executive.

The group chief executive explains how he intends to deliver the required outcome in annual and medium-term plans, the former of which include a comprehensive assessment of the risks to delivery. Progress towards the expected outcome is set out in a monthly report that covers actual results and a forecast of results for the current year. This report is reviewed at each board meeting.

The board/executive relationship policy also sets out how the group chief executive's performance will be monitored and recognizes that, in the multitude of changing circumstances, judgement is always involved. The group chief executive is obliged through dialogue and systematic review to discuss with the board all material matters currently or prospectively affecting the company and its performance and all strategic projects or developments. This specifically includes any materially under-performing business activities and actions that breach the executive limitations policy. It also includes social, environmental and ethical considerations. This dialogue is a key feature of the board/executive relationship. Between board meetings the chairman has responsibility for ensuring the integrity and effectiveness of the board/executive relationship. The systems set out in the board/executive relationship policy are designed to manage, rather than to eliminate, the risk of failure to achieve the board goals policy or observe the executive limitations policy. They provide reasonable, not absolute, assurance against material misstatement or loss.

Combined Code compliance and internal control review

BP complied throughout 2002 with the provisions of Section 1 of the Combined Code Principles of Good Governance, except in the following aspect. Not all the members of the Nomination Committee are identified in this report since three of its members are selected from among the non-executive directors when a meeting is arranged. Leaving part of the committee membership unspecified allows the board to manage the potential for conflicts of interest in the committee's work.

The board's governance policies include a process for the board to review regularly the effectiveness of the system of internal control as required by Code provision D.2.1. As part of this process, the board, the Audit Committee and the Ethics and Environment Assurance Committee requested, received and reviewed reports from executive management and the management of the principal businesses at their regular meetings. That enabled them to assess the effectiveness of the system of internal control in operation for managing significant risks throughout the year. These risks included those areas identified in the Disclosure Guidelines on Socially Responsible Investment issued by the Association of British Insurers. An explanation of how certain of these risks are identified and managed in the course of the company's business is included in the 'Dealing with risks' section on page 20 of this report.

The executive management presented a report to the November meetings of both the Audit Committee and the Ethics and Environment Assurance Committee to support the board in its annual assessment of internal control. The report identified and evaluated significant risks and described the executive management's assurance process. It also described the changes since the last annual assessment in the nature and potential impact of significant risks and the continuing development of the internal control systems in place to manage them. Significant incidents that occurred during the year and management's response to them were also described. The report also included an assessment of future potentially significant risks.

In the board's view, the information it received was sufficient to enable it to review the effectiveness of the company's system of internal control in accordance with the Guidance for Directors on Internal Control (Turnbull).

Directors' interests

in BP ordinary shares or calculated equivalents

	At 31 Dec 2002	At 1 Jan 2002 or on appointment	Change from 31 Dec 2002-11 Feb 2003
Current directors (excluding those appointed in 2003)			
The Lord Browne of Madingley	1,681,652[a]	1,392,184[a]	–
J H Bryan	98,760[b]	98,760[b]	–
R F Chase	810,826	794,745	186
E B Davis, Jr	63,814[b]	62,695[b]	–
Dr B E Grote	722,562[b]	595,845[b]	–
Dr D S Julius	2,000	2,000	–
C F Knight	92,238[b]	30,247[b]	–
F A Maljers	33,492[b]	33,492[b]	–
Dr W E Massey	48,232[b]	47,378[b]	–
H M P Miles	22,145	9,445	–
Sir Robin Nicholson	3,758	3,643	–
R L Olver	738,563	585,852	2,573
Sir Ian Prosser	2,826	2,826	–
P D Sutherland	7,079	7,079	–
M H Wilson	43,200[b]	43,200[b]	–
	At retirement[c]	At 1 Jan 2002	
Directors leaving the board in 2002			
Dr J G S Buchanan	890,409	723,149	
W D Ford	435,607[b]	333,139[b]	
Sir Robert Wilson	5,478	5,478	
		On appointment on 1 Feb 2003	Change from 1 Feb 2003-11 Feb 2003
Directors appointed in 2003			
Dr D C Allen		306,565[d]	–
Dr A B Hayward		91,777	96
J A Manzoni		95,552	99

[a] Includes 50,368 shares held as ADSs throughout 2002.
[b] Held as ADSs.
[c] At retirement on 21 November 2002, 31 March 2002 and 18 April 2002 respectively.
[d] Includes 25,368 shares held as ADSs.

In disclosing the above interests to the company under the Companies Act 1985, directors did not distinguish their beneficial and non-beneficial interests.
Executive directors are also deemed to have an interest in such shares of the company held from time to time by BP QUEST Company Limited and The BP Employee Share Ownership Plan (No. 2) to facilitate the operation of the company's option schemes.
No director has any interest in the preference shares or debentures of the company, or in the shares or loan stock of any subsidiary company.

Directors' remuneration report

The directors' remuneration report this year has a new format that is designed to comply with requirements introduced by the Directors' Remuneration Report Regulations 2002. The report covers all directors, both executive and non-executive.

The report, which is set out on pages 30 to 39, is divided into two parts. Each part contains a section that is subject to audit. Executive directors' remuneration is in the first part, which was prepared by the remuneration committee. Non-executive directors' remuneration is in the second part, which was prepared by the company secretary on behalf of the board.

The report has been approved by the board and signed on its behalf by the company secretary. This report is subject to the approval of shareholders at the annual general meeting.

Part 1 – Executive directors' remuneration

Dear Shareholder

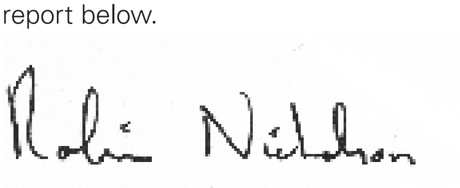
The remuneration committee places high value on the independence both of its decision-making processes and of the advice it receives. Throughout a sometimes challenging year, this independence has enabled the committee to take decisions on executive director remuneration that properly align directors' remuneration with the interests of shareholders while also meeting the imperative of retaining and engaging the world-class executive talent we are fortunate to have leading our company.

Our commitment to link pay to performance continues. In 2002, the company produced strong results in many areas of the business, balanced by a few disappointments. As you will see, the rating for the annual bonus for 2002, which assesses the full breadth of performance during the year, is some 11% lower than last year, reflecting good, but less favourable, overall performance this year. The expected award of shares under the Long Term Performance Plan for the period 2000-2002 is less than half last year's award.

Our approach to policy for 2003 will continue to be as for the past several years and will be underpinned by regular monitoring of remuneration policies and levels at competitor companies in Europe and the USA. The Executive Directors' Incentive Plan, which was approved by shareholders in April 2000, continues to be competitive and will again be used as last year. Details of this plan are explained on pages 32 and 33.

In 2003, the committee will continue to review the remuneration plans that apply to executive directors to ensure they meet the dual needs of alignment with shareholders' interests and of the retention and engagement of our executives. Consistent with our well-established policy of transparency, any significant changes we feel are warranted will be brought to shareholders for approval at a future annual general meeting.

Full details of the 2002 remuneration of executive directors and all other information about executive directors required under the Directors' Remuneration Report Regulations 2002 are contained in the committee's report below.



Sir Robin Nicholson
Chairman, Remuneration Committee
11 February 2003

This report sets out the company's policy on executive directors' remuneration for 2003 and, so far as practicable, for subsequent years. The inclusion in the report of remuneration policy in respect of years after 2003 is required by the legislation under which this report is prepared.

The remuneration committee is able to state its remuneration policy for 2003 with reasonable certainty, but is less certain that this policy will continue without amendment in subsequent years. This is because the committee considers that a successful remuneration policy needs to be sufficiently flexible to take account of future changes in BP's business environment and in remuneration practice. Any changes in policy for years after 2003 will be described in future directors' remuneration reports, which will continue to be subject to shareholder approval. All statements in this report in relation to remuneration policy for years after 2003 should be read in the light of this paragraph.

The remuneration committee

Tasks

The committee's tasks as set out in the board governance policies are:

- To determine on behalf of the board the terms of engagement and remuneration of the group chief executive and the executive directors and to report on those to the shareholders.
- To determine on behalf of the board matters of policy over which the company has authority relating to the establishment or operation of the company's pension scheme of which the executive directors are members.
- To nominate on behalf of the board any trustees (or directors of corporate trustees) of such scheme.
- To monitor the policies being applied by the group chief executive in remunerating senior executives other than executive directors.

Constitution and operation

The committee members are all non-executive directors. The membership throughout 2002 was: Sir Robin Nicholson (chairman), Mr Davis, Dr Julius, Mr Knight and Sir Ian Prosser. Like other directors, each member of the committee is subject to re-election every three years. They have no personal financial interest, other than as shareholders, in the committee's decisions. They have no conflicts of interest arising from cross-directorships with the executive directors nor from being involved in the day-to-day business of the company. The committee met five times in the period under review.

In its constitution and operation the committee complies with the Combined Code on Corporate Governance. It is accountable to shareholders through its annual report on executive directors' remuneration. The committee will consider the outcome of the vote on the remuneration report, and the views of investors will be taken into account by the committee in its future decisions.

Advice

Advice is provided to the committee by the company secretary's office, which is independent of executive management and reports to the non-executive chairman. Mr Gerrit Aronson, who is an independent consultant within the company secretary's office, was appointed in 2000 by the committee as its secretary and special adviser. He does not provide any other services to the group.

The committee, in consultation with Mr Aronson and the company secretary, also appoints external professional advisers to provide specialist advice and services on particular remuneration matters. This allows for a range of external independent opinion to be sourced by the committee. This advice is then subject to an independent review by Mr Aronson. The committee assesses the advice it receives, applying its own judgement. Procedures to ensure the independence of advice are subject to annual review.

During 2002, the following people provided advice or services on specific matters to the committee that materially assisted it in its consideration of matters relating to executive directors' remuneration:

- Mr Sutherland (chairman); Lord Browne (group chief executive), who was consulted on matters relating to the other executive directors who report to him and on matters relating to the performance of the company. He was not present when matters affecting his own remuneration were considered; Mr Iain Macdonald (group vice president, planning, performance management and control, for the company), who provided to the committee some of the company's calculations for the performance-related pay which were then subject to independent verification by Ernst & Young as auditors; Mr Aronson; Miss Hanratty (company secretary); and Mrs Sarah Martin (senior counsel, company secretary's office). Only Mr Aronson among those above was appointed by the committee.
- Towers Perrin who, during 2002, have been the committee's principal advisers on matters of executive directors' remuneration and who also provided some ad hoc remuneration and benefits advice to parts of the group, mainly comprising pensions advice in Canada; Kepler Associates, who advised on the selection of the shareholder return against the market performance benchmark for the Executive Directors' Incentive Plan and tracked BP's performance against this benchmark (they provided a similar service in relation to the Long Term Performance Plan for senior executives); Freshfields Bruckhaus Deringer, Allen & Overy and Martin Moore, QC, all of whom provided legal advice on specific matters to the committee and who provide ad hoc legal advice to the group; and Ernst & Young in their capacity as auditors, who reviewed and reported to the committee on the calculations of BP's performance in respect of financial targets that form the basis for performance-related pay for the executive directors, and who also provide audit, audit-related and taxation services to the group. All the above were appointed separately by the committee or the secretary to the committee to provide the advice or services that it sought, except for Kepler Associates, who were appointed by the group chief executive and subsequently provided information to the remuneration committee.

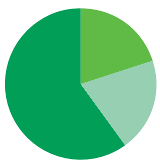
Policy on executive directors' remuneration

Main principles

The remuneration committee's reward policy reflects its obligation to align executive directors' remuneration with shareholders' interests and to engage world-class executive talent for the benefit of the group. The main principles of the policy are:

- Total rewards should be set at appropriate levels to reflect the competitive global market in which BP operates.
- The majority of the total reward should be linked to the achievement of demanding performance targets.
- Executive directors' incentives should be aligned with the interests of ordinary shareholders. This is achieved through setting performance targets that are based on measures of shareholders' interests and through the committee's policy that each executive director should hold a significant shareholding in the company, currently equivalent to 5 x the director's base salary.
- The performance targets in the Executive Directors' Incentive Plan should encompass demanding comparisons of BP's shareholder returns and earnings with those of other companies in its own industry and in the broader marketplace.
- The wider scene, including pay and employment conditions elsewhere in the group, should be taken into account, especially when determining annual salary increases.

Elements of remuneration
The executive directors' total remuneration consists of salary, annual bonus, long-term incentives, pensions and other benefits. This reward structure is regularly reviewed by the committee to ensure that it is achieving its objectives. In 2003, over three-quarters of executive directors' potential direct remuneration will again be performance-related *(see illustrative chart below)*. It is intended that this balance of elements should continue.



base salary

performance-related annual bonus

performance-related long-term incentives include a share element and options

The above elements are valued at on-target basis.

Salary
Each executive director receives a fixed sum payable monthly in cash. The committee expects to review salaries later in 2003 in line with global markets. The appropriate survey groups are defined and analysed by external remuneration advisers.

Annual bonus
Each executive director is eligible to participate in an annual performance-based bonus scheme. The remuneration committee reviews and sets bonus targets and levels of eligibility annually. The target level is 100% of base salary (except for Lord Browne, for whom, as group chief executive, it is considered appropriate to have a target of 110%). There is a stretch level of 150% of base salary for substantially exceeding targets. Executive directors' annual bonus awards for 2003 will again be based on a mix of demanding financial targets and other leadership objectives, established at the beginning of the year. In addition to business performance, they cover areas such as people, safety, environment and organization.

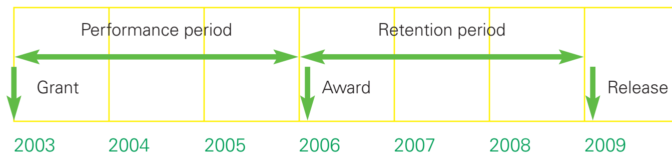
Long-term incentives
Long-term incentives are provided under the Executive Directors' Incentive Plan (EDIP), which was approved by shareholders in April 2000. It has three elements: a share element, a share option element and a cash element. Each executive director participates in this plan. The committee's policy, subject to unforeseen circumstances, is that this should continue until the plan expires or is renewed in 2005. The committee's policy for 2003 is to continue to use only the share element and the share option element. The committee's policy that each executive director should hold shares equivalent to 5 x the director's base salary is reflected in the terms of the plan.

The performance conditions in the share element and share option element of the EDIP were selected to ensure that executive directors' long-term remuneration under the EDIP is appropriately balanced between elements testing BP's performance against that of competitors in the oil industry and elements testing BP's performance against that of the leading global companies.

1. Share element
The share element permits the remuneration committee to grant 'performance units' to executive directors, which may result in an award of shares (without payment by the directors) at the end of a three-year performance period if demanding performance conditions are met. The maximum number of shares that may be awarded for each performance unit is two.

Shares awarded are then held in trust for three years before they are released to the individual. This gives the executive directors a six-year incentive structure, and ensures their interests are aligned with those of shareholders.

Timeline for 2003-2005 EDIP share element



The share element compares BP's performance against the oil and gas sector over three years on a rolling basis. This is assessed in terms of a three-year total shareholder return against the market (SHRAM), return on average capital employed (ROACE) and earnings per share growth, based on pro forma results adjusted for special items (EPS). SHRAM is the primary measure, accounting for nearly two-thirds of the potential total award. All calculations are reviewed by the auditors to ensure that they meet an independent objective standard. The relative position of the company within the comparator group determines the number of shares awarded per performance unit.

For the 2001-2003 plan, BP's three-year SHRAM is measured against the other oil majors: ExxonMobil, Shell, TotalFinaElf and ChevronTexaco. Due to the reduced number of oil majors, for the 2002-2004 and 2003-2005 plans BP's three-year SHRAM is measured against the companies in the FTSE All World Oil & Gas Index. Companies within the index are weighted according to their market capitalization at the beginning of each three-year period in order to give greatest emphasis to oil majors.

The committee reviews and approves annually the performance measures and the comparator companies. The policy for 2003 and for the foreseeable future is to continue with the SHRAM measure adopted by the committee in relation to the 2002-2004 and 2003-2005 plans.

BP's ROACE and EPS for all the plans since April 2001 are, and for the foreseeable future will be, measured against ExxonMobil, Shell, TotalFinaElf and ChevronTexaco.

2. Share option element
The share option element of the EDIP is designed to reflect BP's performance relative to a wider selection of global companies. It has a disclosed three-year pre-grant performance requirement that differentiates it from traditional share option schemes. Under this element, options may be granted to executive directors at an exercise price no lower than the market value (as determined in accordance

with the plan rules) of a share at the date the option is granted. Reflecting the pre-grant performance requirement, options vest over three years after grant (one-third each after one, two and three years respectively). They have a life of seven years after grant.

In accordance with the framework approved by shareholders in 2000, it is the committee's policy to continue exercising its judgement to decide the number of options to be granted to each executive director, taking into account BP's total shareholder return (TSR) compared with the TSR for the FTSE Global 100 group of companies over the three years preceding the grant. The committee will not grant options in any year unless the criteria for an award of shares under the share element have been met. These methods of calculation were chosen to enable the committee to take into account not only the TSR position but also the underlying health of the business and the competitive marketplace.

Following grant, the options are not subject to any performance conditions. The remuneration committee favours this approach for two main reasons. First, it has the effect of treating share options as a reward both for past performance (because BP's ranking within a comparator group will have been taken into account in determining the number of shares under option) and as an incentive for future performance (because the participant's gain under the option will depend on share price growth after the grant under the option). Second, BP operates internationally and the application of a performance condition after grant is not a feature of option schemes operated by major international companies based outside the UK.

3. Cash element

The cash element allows the remuneration committee to grant cash rather than share-based incentives in exceptional circumstances. This element was not used in 2002, and the committee has no present intention to use it in 2003.

Other benefits

- Pension – executive directors are eligible to participate in the appropriate pension schemes applying in their home countries as described on page 37.
- Benefits and other share schemes – executive directors are eligible to participate in regular employee benefit plans and in all-employee share schemes and savings plans applying in their home countries. Benefits in kind are not pensionable.
- Resettlement allowance – expatriates may receive a resettlement allowance for a limited period.

New appointees

Dr Allen, Dr Hayward and Mr Manzoni were appointed executive directors on 1 February 2003, each on a base salary of £400,000 per annum. They are subject to the committee's policy on executive directors' remuneration, as described above. As such, they will be eligible to participate in the annual bonus scheme and EDIP described above on a similar basis to the other executive directors.

Service contracts

Policy

The committee's policy on executive directors' service contracts is for them to contain a maximum notice period of one year. To reflect current market practice, Lord Browne has agreed to reduce the notice period in his contract to one year and it has been amended to reflect this. All executive directors' service contracts now either expire this year or can be terminated on one year's notice.

Each service contract expires at the respective normal retirement date of the director but is subject to earlier termination for cause or if notice is given under the contract.

The contracts are designed to allow for flexibility to deal with each case on its own particular merits in accordance with the law and policy as they have developed at the relevant time. With effect from January 2003, the committee will include a provision in new service contracts to allow for severance payments to be phased where appropriate to do so. It will also consider mitigation to reduce compensation to a departing director where appropriate to do so. A large proportion of each executive director's total remuneration is linked to performance and therefore will not be payable to the extent that the relevant targets are not met.

Specific contracts

Lord Browne's service contract with the company is dated 11 November 1993. It can be terminated by the company or by Lord Browne by one year's notice.

Dr Buchanan's service contract with the company is dated 21 October 1998 and expires at his normal retirement date in June 2003.

Mr Chase's service contract with the company is dated 30 November 1993 and expires at his normal retirement date in May 2003.

Dr Grote's service contract with BP Exploration (Alaska) Inc. is dated 7 August 2000. It can be terminated by that company or by Dr Grote by one year's notice. He is seconded to BP p.l.c. under a secondment agreement that is dated 7 August 2000. At 31 December 2002, this secondment agreement had an unexpired term of five years. The secondment may be terminated by one month's notice by either party and terminates automatically on the termination of Dr Grote's service contract.

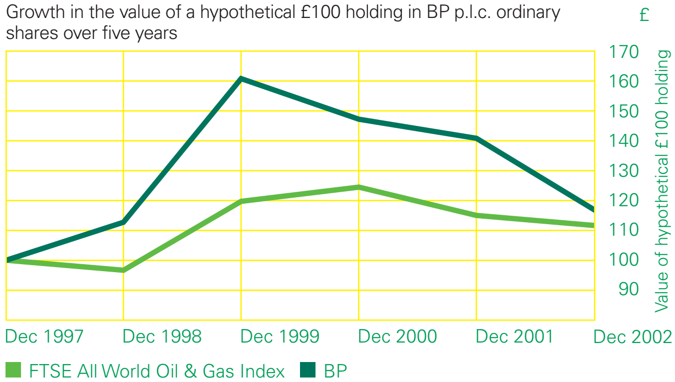
Mr Olver's service contract with the company is dated 31 December 1997. It can be terminated by the company or by Mr Olver by one year's notice. The company may also terminate the contract at any time with immediate effect on payment in lieu of notice equivalent to one year's salary or the amount of salary that would have been paid if the contract had terminated on the expiry of the remainder of the notice period.

There are no other provisions for compensation payable on early termination of the above contracts. In the event of early termination under any of the above contracts by the company other than for cause (or under a specific termination payment provision), the relevant director's then current salary and contractual benefits would be taken into account in calculating any liability of the company. The principal contractual benefits provided in addition to salary are the provision of a car or car allowance, pension and life insurance. Annual bonuses and long-term incentives are non-contractual and are dealt with in accordance with the rules of the relevant schemes.

Details in relation to Mr Ford's contract are included on page 37.

Historical TSR performance

Growth in the value of a hypothetical £100 holding in BP p.l.c. ordinary shares over five years



This graph is included to meet the new requirement to show the growth in the value of a hypothetical £100 holding in BP p.l.c. ordinary shares over five years relative to a broad equity market index. The FTSE All World Oil & Gas Index was considered by the remuneration committee to be the most relevant index for this purpose as it relates directly to BP's sector.

Information subject to audit

Summary of 2002 remuneration

	Annual remuneration					Long Term Performance Plan (LTPP)				Grants under EDIP	
	Salary '000	2002 annual performance bonus '000	Other benefits '000	**2002 total '000**	2001 total '000	**2000-2002 LTPP** (awarded in Feb 2003) Expected award[a] (shares)	Value[b] '000	1999-2001 LTPP (awarded in Feb 2002) Actual award (shares)	Value[c] '000	2002-2004 share element (granted in Feb 2002) (performance units)[d]	Share option element (options)[e]
The Lord Browne	$1,926	$2,543	$78	**$4,547**	$4,373	224,000	$1,324	472,500	$3,875	475,556	1,348,032
of Madingley	*£1,284*	*£1,695*	*£52*	*£3,031*	*£3,037*		*£883*		*£2,691*		
R F Chase	$960	$1,152	$47	**$2,159**	$2,042	139,200	$823	315,000	$2,583	272,031	–
	£640	*£768*	*£32*	*£1,440*	*£1,418*		*£548*		*£1,794*		
Dr B E Grote	$713	$856	$302[f]	**$1,871**	$1,864	68,000	$402	175,000	$1,436	182,613	349,038
	£475	*£570*	*£202*	*£1,247*	*£1,294*		*£268*		*£997*		
R L Olver	$795	$954	$56	**$1,805**	$1,717	117,600	$695	252,000	$2,066	196,296	370,956
	£530	*£636*	*£37*	*£1,203*	*£1,192*		*£463*		*£1,435*		
Directors leaving the board in 2002[g]											
Dr J G S Buchanan	$715	$787	$26	**$1,528**	$1,656	123,200	$728	280,000	$2,297	221,026	–
	£477	*£524*	*£17*	*£1,018*	*£1,150*		*£485*		*£1,595*		
W D Ford	$180	$180	$148[f]	**$508**	$2,188	105,600	$624	175,000	$1,436	–	–
	£120	*£120*	*£99*	*£339*	*£1,519*		*£416*		*£997*		

The table above represents remuneration received by executive directors in the 2002 financial year, with the exception of the 2002 annual bonus which was earned in 2002 but paid in 2003. Amounts are shown in both US dollars and pounds sterling and are converted at the rate of £1 = $1.44 for 2001 and £1 = $1.50 for 2002. Lord Browne, Mr Chase, Mr Olver and Dr Buchanan received their remuneration in pounds sterling; Dr Grote and Mr Ford in US dollars.

[a] Gross award of shares based on a performance assessment by the remuneration committee and on the other terms of the plan. Sufficient shares are sold to pay for tax applicable. Remaining shares are held in trust until 2006 when they are released to the individual.
[b] Based on closing price of BP shares on 11 February 2003 (£3.94/$5.91 at £1 = $1.50).
[c] Based on average market price on date of award (£5.695/$8.20 at £1 = $1.44).
[d] Performance units granted under the 2002-2004 share element of the EDIP are converted to shares at the end of the performance period. Maximum of two shares per performance unit.
[e] Options granted in February 2002 have a grant price of £5.715 per share. Dr Grote holds options over ADSs; the above numbers and prices reflect calculated equivalents.
[f] Includes resettlement allowances for Dr Grote and Mr Ford of $300,000 and $110,000 respectively.
[g] Amounts for Dr Buchanan and Mr Ford reflect the eleven months and three months respectively that they were directors in 2002.

Salary

In January 2002 base salaries for executive directors were increased by less than 10% per annum. Base salaries have recently been increased by 5% per annum both for Dr Grote on his promotion to chief financial officer and for Mr Olver on his promotion to deputy group chief executive.

Annual bonus

The annual bonus awards for 2002 are based on a mix of financial targets and leadership objectives established at the beginning of the year. Assessment of all the targets resulted in a target performance of 120 points out of a maximum of 150, which is some 11% lower than the 135 points last year. The resulting bonus awards are shown in the summary table above. All calculations in relation to the annual bonus have been reviewed by the auditors.

Share options

	Option type	At 1 Jan 2002	Granted	Exercised	At 31 Dec 2002	Option price	Market price at date of exercise	Date from which first exercisable	Expiry date
The Lord Browne of Madingley	SAYE	5,968	–	5,968	–	£2.89	£4.52	1 Sept 2002	28 Feb 2003
	SAYE	–	3,661	–	3,661	£4.52	–	1 Sept 2007	28 Feb 2008
	EDIP	408,522	–	–	408,522	£5.99	–	15 May 2001	15 May 2007
	EDIP	1,269,843	–	–	1,269,843	£5.67	–	19 Feb 2002	19 Feb 2008
	EDIP	–	1,348,032	–	1,348,032	£5.72	–	18 Feb 2003	18 Feb 2009
R F Chase	SAYE	3,388	–	–	3,388	£4.98	–	1 Sept 2005	28 Feb 2006
	EDIP	85,215	–	–	85,215	£5.99	–	15 May 2001	15 May 2007
	EDIP	312,171	–	–	312,171	£5.67	–	19 Feb 2002	19 Feb 2008
Dr B E Grote[a]	SAR	40,000	–	–	40,000	$13.63	–	23 Mar 1996	23 Mar 2003
	SAR	40,800	–	–	40,800	$16.63	–	25 Mar 1997	25 Mar 2004
	SAR	35,600	–	–	35,600	$19.16	–	28 Feb 1998	28 Feb 2005
	SAR	35,200	–	–	35,200	$25.27	–	6 Mar 1999	6 Mar 2006
	SAR	40,000	–	–	40,000	$33.34	–	28 Feb 2000	28 Feb 2007
	BPA	10,404	–	–	10,404	$53.90	–	15 Mar 2000	14 Mar 2009
	BPA	12,600	–	–	12,600	$48.94	–	28 Mar 2001	27 Mar 2010
	EDIP	40,182	–	–	40,182	$49.65	–	19 Feb 2002	19 Feb 2008
	EDIP	–	58,173	–	58,173	$48.82	–	18 Feb 2003	18 Feb 2009
R L Olver	SAYE	2,386	–	–	2,386	£2.89	–	1 Sept 2002	28 Feb 2003
	SAYE	1,137	–	–	1,137	£5.11	–	1 Sept 2004	28 Feb 2005
	SAYE	–	840	–	840	£4.52	–	1 Sept 2005	28 Feb 2006
	EDIP	71,847	–	–	71,847	£5.99	–	15 May 2001	15 May 2007
	EDIP	260,319	–	–	260,319	£5.67	–	19 Feb 2002	19 Feb 2008
	EDIP	–	370,956	–	370,956	£5.72	–	18 Feb 2003	18 Feb 2009
Directors leaving the board in 2002									
Dr J G S Buchanan[b]	SAYE	1,856	–	–	1,856	£3.71	–	1 Sept 2003	28 Feb 2004
	SAYE	750	–	–	750	£4.49	–	1 Sept 2004	28 Feb 2005
	SAYE	1,320	–	–	1,320	£5.11	–	1 Sept 2006	28 Feb 2007
	EDIP	75,189	–	–	75,189	£5.99	–	15 May 2001	15 May 2007
	EDIP	253,971	–	–	253,971	£5.67	–	19 Feb 2002	19 Feb 2008
W D Ford[a, c]	NRSO	105,866	–	–	105,866	$20.80	–	22 Mar 1995	22 Mar 2004
	NRSO	119,100	–	–	119,100	$23.69	–	28 Mar 1996	28 Mar 2005
	NRSO	132,332	–	–	132,332	$27.68	–	26 Mar 1997	26 Mar 2006
	NRSO	132,332	–	–	132,332	$34.08	–	25 Mar 1998	25 Mar 2007
	NRSO	132,332	–	–	132,332	$32.92	–	24 Mar 1999	24 Mar 2008
	BPA	54,712	–	–	54,712	$53.90	–	15 Mar 2000	14 Mar 2009
	BPA	38,750	–	–	38,750	$48.94	–	28 Mar 2001	27 Mar 2010
	EDIP	43,506	–	–	43,506	$49.65	–	19 Feb 2002	19 Feb 2008

The closing market prices of an ordinary share and of an ADS on 31 December 2002 were £4.27 and $40.65 respectively. During 2002, the highest market prices were £6.25 and $53.88 respectively, and the lowest market prices were £3.93 and $36.78 respectively.

EDIP = Executive Directors' Incentive Plan adopted by shareholders in April 2000 as described on pages 32-33. The awards are made taking into consideration the ranking of the company's TSR against the TSR of the FTSE Global 100 group of companies over the three-year period prior to the grant. As noted in last year's report, for directors who retire after 1 January 2002, options that are vested at a director's retirement will now be preserved until the normal lapse date (the seventh anniversary of grant).
BPA = BP Amoco share option plan, which applied to US executive directors prior to the adoption of the EDIP.
NRSO = Amoco Non-Restricted Stock Option Plan, which applied to Mr Ford as an employee of Amoco.
SAR = Stock Appreciation Rights under BP America Inc. Share Appreciation Plan.
In keeping with the US market practice, none of the options under the BPA, NRSO and SAR is subject to performance conditions because they were granted under American plans to the relevant individuals and the NRSO options were awarded prior to Amoco's merger with BP.
SAYE = Save As You Earn employee share option scheme. These options are not subject to performance conditions because this is an all-employee share scheme governed by specific tax legislation.

[a] Numbers shown are ADSs under option. One ADS is equivalent to six ordinary shares.
[b] On leaving the board of BP p.l.c. on 21 November 2002.
[c] On leaving the board of BP p.l.c. on 31 March 2002.

Long Term Performance Plans (LTPPs) and share element of EDIP

Under the Long Term Performance Plans and the share element of the EDIP, performance units are granted at the beginning of the period and converted into an award of shares at the end of the three-year period, depending on performance. There is a maximum of two shares per performance unit.

Since the adoption of the EDIP in April 2000, the executive directors have ceased to be eligible for grants under the BP share option plan and the LTPPs. However, they were not required to relinquish rights under those plans that had already been granted prior to April 2000 (including performance units under the LTPPs that have yet to mature into share awards).

The last of these LTPP rights under the 1999-2001 and 2000-2002 plans matured or mature into share awards in February 2002 and 2003 respectively.

For the 2000-2002 LTPP, BP's performance was assessed in terms of SHRAM, ROACE and EPS growth – each relative to that of ExxonMobil, Shell, TotalFinaElf, ChevronTexaco, ENI and Repsol-YPF.

BP's SHRAM came in at sixth place among the comparator group, fourth place on EPS growth and first place on ROACE.

Based on a performance assessment of 80 points out of 200, the remuneration committee expects to make awards of shares to executive directors as highlighted in the 2000-2002 lines of the table below.

The table also sets out information in compliance with new legal requirements introduced under the Directors' Remuneration Report Regulations 2002. For the purpose of these regulations, performance units are scheme interests.

Long Term Performance Plans (LTPPs) and share element of EDIP

				LTPP/Share element interests			Interests vested in 2002		
				Performance units[b]					
	Performance period[a]	Date of grant of performance units	Market price of each share at date of grant of performance units £	At 1 Jan 2002	Granted 2002	At 31 Dec 2002	Number of ordinary shares awarded[c]	Share award date	Market price of each share at share award date £
The Lord Browne of Madingley	1999-2001	11 Mar 1999	5.11	270,000	–	–	472,500	19 Feb 2002	5.70
	2000-2002	**23 Feb 2000**	**4.59**	**280,000**	**–**	**280,000**	**224,000**	**expected award Feb 2003**	
	2001-2003	19 Feb 2001	5.80	415,000	–	415,000	–	–	–
	2002-2004	18 Feb 2002	5.73	–	475,556	475,556	–	–	–
R F Chase	1999-2001	11 Mar 1999	5.11	180,000	–	–	315,000	19 Feb 2002	5.70
	2000-2002	**23 Feb 2000**	**4.59**	**174,000**	**–**	**174,000**	**139,200**	**expected award Feb 2003**	
	2001-2003	19 Feb 2001	5.80	205,000	–	205,000	–	–	–
	2002-2004	18 Feb 2002	5.73	–	237,037	237,037	–	–	–
	2002-2004	13 Mar 2002	6.17	–	34,994	34,994	–	–	–
Dr B E Grote	1999-2001	11 Mar 1999	5.11	100,000	–	–	175,000	19 Feb 2002	5.70
	2000-2002	**23 Feb 2000**	**4.59**	**85,000**	**–**	**85,000**	**68,000**	**expected award Feb 2003**	
	2001-2003	19 Feb 2001	5.80	155,000	–	155,000	–	–	–
	2002-2004	18 Feb 2002	5.73	–	182,613	182,613	–	–	–
R L Olver	1999-2001	11 Mar 1999	5.11	144,000	–	–	252,000	19 Feb 2002	5.70
	2000-2002	**23 Feb 2000**	**4.59**	**147,000**	**–**	**147,000**	**117,600**	**expected award Feb 2003**	
	2001-2003	19 Feb 2001	5.80	170,000	–	170,000	–	–	–
	2002-2004	18 Feb 2002	5.73	–	196,296	196,296	–	–	–
Directors leaving the board in 2002									
Dr J G S Buchanan	1998-2000	5 Feb 1998	4.05	159,900[d]	–	–	–	–	–
	1999-2001	11 Mar 1999	5.11	160,000	–	–	280,000	19 Feb 2002	5.70
	2000-2002	**23 Feb 2000**	**4.59**	**154,000**	**–**	**154,000[e]**	**123,200**	**expected award Feb 2003**	
	2001-2003	19 Feb 2001	5.80	165,000	–	165,000[e]	–	–	–
	2002-2004	18 Feb 2002	5.73	–	192,593	192,593[e]	–	–	–
	2002-2004	13 Mar 2002	6.17	–	28,433	28,433[e]	–	–	–
W D Ford	1999-2001	11 Mar 1999	5.11	100,000	–	–	175,000	19 Feb 2002	5.70
	2000-2002	**23 Feb 2000**	**4.59**	**132,000**	**–**	**132,000[f]**	**105,600**	**expected award Feb 2003**	
	2001-2003	19 Feb 2001	5.80	170,000	–	170,000[f]	–	–	–
Former director									
Dr C S Gibson-Smith	1999-2001	11 Mar 1999	5.11	144,000	–	–	252,000	19 Feb 2002	5.70
	2000-2002	**23 Feb 2000**	**4.59**	**140,000**	**–**	**140,000**	**112,000**	**expected award Feb 2003**	

[a] For performance periods up to 2000-2002, performance units were granted under the LTPPs. Thereafter they were granted under the EDIP as explained on pages 32-33. Each performance period ends on 31 December of the third year.

[b] Represents number of performance units, each having a maximum potential of two shares depending on performance.

[c] Represents awards of shares made or expected to be made at the end of the relevant performance period based on performance achieved under rules of the plan. BP's performance is assessed in terms of a three-year SHRAM against the oil majors. For 1998-2000 this included ExxonMobil, Shell, TotalFinaElf, ChevronTexaco; for 1999-2001 this included ExxonMobil, Shell, TotalFinaElf, ChevronTexaco; and for 2000-2002 this included ExxonMobil, Shell, TotalFinaElf, ChevronTexaco, ENI, Repsol-YPF. For the two latter plans, performance was also assessed in terms of ROACE and EPS growth against the same oil majors.

[d] Dr Buchanan elected to defer to 2004 the determination of whether an award should be made for this period.

[e] On leaving the board of BP p.l.c. on 21 November 2002.

[f] On leaving the board of BP p.l.c. on 31 March 2002.

Compensation for past directors

Mr Ford's service agreement was with BP Corporation North America Inc. (BPCNA), dated 23 June 2000. Mr Ford was seconded to BP p.l.c. under a secondment agreement dated 23 June 2000. On his resignation from the board of BP p.l.c. with effect from 31 March 2002, his secondment to BP p.l.c. ended and he returned to the USA. His underlying US employment agreement with BPCNA had a two-month notice period and was due to expire on 21 January 2004. His contract was terminated early by BPCNA on 1 June 2002 in accordance with its terms. The contract terms required payment to him by BPCNA of liquidated damages of $1,655,555, being equivalent to $1 million per annum (pro rated for part years) for each year between the date of severance and 21 January 2004. BPCNA also made payments totalling $129,691 to Mr Ford in June 2002 in accordance with its standard benefits and repatriation programme. Mr Ford remains eligible for a pro rata award under the 2002 annual bonus scheme and for awards under the long-term incentive schemes in accordance with the rules of those schemes.

Pensions

$ thousand	Service at 31 Dec 2002	Accrued pension entitlement at 31 Dec 2002	Additional pension earned during the year ended 31 Dec 2002	Transfer value of accrued benefit at 31 Dec 2002 (A)	Transfer value of accrued benefit at 31 Dec 2001 (B)	Amount of A-B less contributions made by the director in 2002
The Lord Browne of Madingley (UK)	36 years	1,284	84	19,143	16,335	2,808
Dr J G S Buchanan (UK)	33 years	520	40	9,586	8,652	934
R F Chase (UK)	38 years	640	50	11,649	10,633	1,016
W D Ford (USA)[a]	31 years	644	140	8,324	5,988	2,336
Dr B E Grote (USA)	23 years	263	181	3,493	1,069	2,424
R L Olver (UK)	29 years	530	40	8,210	6,955	1,255

Conversion rates: 2002 at £1 = $1.50; 2001 at £1 = $1.44.

[a] 2002 figures for Mr Ford are stated as at 31 March 2002, the date he left the board of BP p.l.c. He retired in June 2002 and, in accordance with his entitlements under the normal rules of the 'grandfathered' plan, he took a lump-sum distribution in August 2002 of his combined plan benefits totalling $8,485,733.

UK directors

UK directors are members of the BP Pension Scheme. The scheme offers Inland Revenue-approved retirement benefits based on final salary. It is the principal section of the BP Pension Fund, the latter being set up under trust deed. Company contributions to the fund are made on the advice of the actuary appointed by the trustee. No company contributions were made during 2002.

Scheme members' core benefits are non-contributory. They include a pension accrual of 1/60th of basic salary for each year of service, subject to a maximum of two-thirds of final basic salary; a lump-sum death-in-service benefit of 3 x salary; and a dependant's benefit of two-thirds of the member's pension. The scheme pension is not integrated with state pension benefits.

Normal retirement age is 60, but scheme members who have 30 or more years' pensionable service at age 55 can elect to retire early without an actuarial reduction being applied to their pension.

Pensions payable from the fund are guaranteed to be increased annually in line with changes in the Retail Prices Index, up to a maximum of 5% a year.

Directors appointed prior to 2003 accrue pension on a non-contributory basis at the enhanced rate of 2/60ths of their final salary for each year of service as executive directors (up to the same two-thirds limit). None of the directors is affected by the pensionable earnings cap.

In accordance with the company's long-standing practice for executive directors who retire from BP on or after age 55 having accrued at least 30 years' service, Mr Chase will receive an ex-gratia lump-sum superannuation payment from the company equal to one year's base salary following his retirement. Lord Browne will remain eligible for consideration for such a payment. In the case of these individuals, all matters relating to such superannuation payments will be considered by the remuneration committee. Any such payments would be in addition to their pension entitlements referred to above. None of the other executive directors is eligible for consideration for a superannuation payment on retirement, as the remuneration committee decided in 1996 that appointees to the board after that time should cease to be eligible for consideration for such a payment.

US directors

US directors participate in the BP Retirement Accumulation Plan (US plan), which features a cash balance formula. The current design of the US plan became effective on 1 July 2000. However, certain former employees of Amoco and ARCO have been provided with a minimum (or 'grandfathered') benefit equal to the benefit that would have accrued under the respective predecessor pension plan. Mr Ford's pension benefit was subject to this 'grandfathered' arrangement described above, reflecting his Amoco service and benefits.

Consistent with US tax regulations, pension benefits are provided through a combination of tax-qualified and non-qualified benefit restoration plans, as applicable.

The Supplemental Executive Retirement Benefit (supplemental plan) is a non-qualified top-up arrangement that became effective on 1 January 2002 for US employees above a specified salary level. The benefit formula is 1.3% of final average earnings, which comprise base salary and bonus in accordance with standard US practice (as specified under the qualified arrangement) multiplied by years of service, with an offset for benefits payable under all other BP qualified and non-qualified pension arrangements. This benefit is unfunded and therefore paid from corporate assets.

Dr Grote is an eligible participant under the supplemental plan, and his pension accrual for 2002 includes the total amount that may become payable under all plans.

Part 2 – Non-executive directors' remuneration

Dear Shareholder

It is important for BP to attract and retain non-executive talent from around the globe to ensure that our board is able to discharge its stewardship obligations to the highest possible standards, especially as the workload of non-executive directors continues to grow. The recent Higgs Report recognizes that non-executive fees should reflect these greater expectations in the new boardroom environment, both at formal meetings of the board and in the work of its committees, as governance practices evolve. All non-executive members of the BP board serve on at least one of its permanent committees, as described in the corporate governance section on page 28.

The remuneration of non-executive directors was last considered in 2000, with revised fee levels introduced on 1 January 2001. During 2002, the board appointed a committee of independent non-executive directors under my chairmanship, consisting of Dr Julius and Mr Maljers, to review the remuneration of the non-executive directors and make recommendations for future structure and amount. This ad hoc committee is distinct from the remuneration committee, which considers matters relating to the remuneration of the executive directors. The ad hoc committee is not a standing committee of the board and, having undertaken the task assigned to it, it has been dissolved. In the course of its work, the committee received advice and material assistance from Miss Hanratty (company secretary) and Mr Jeremy Booker (vice president corporate governance, company secretary's office).

The ad hoc committee met on three occasions to consider in detail a range of options for the remuneration of non-executive directors, in the light of developing remuneration practice and the anticipated workload, tasks and liabilities of the non-executive directors. Having considered comparative data and practice, including equivalent daily rates for non-executives in relevant jurisdictions, the committee made a number of recommendations to the board. These recommendations were formally adopted by the board and took effect from 1 July 2002.

John H Bryan
Chairman, Ad Hoc Committee on Non-Executive Remuneration
11 February 2003

Policy on non-executive directors' remuneration

In making recommendations for non-executive directors' remuneration, the following policies were developed to guide the board in its current and future decision-making.

- Within the limits set by the shareholders from time to time, remuneration should be sufficient to attract, motivate and retain world-class non-executive talent.
- Remuneration of non-executive directors should be proportional to their contribution towards the interests of the company.
- Remuneration practice should be consistent with recognized best-practice standards for non-executive directors' remuneration.
- Remuneration should be in the form of cash fees, payable monthly.
- Non-executive directors should not receive share options from the company.
- Non-executive directors should be encouraged to establish a holding in BP shares broadly related to one year's base fee, to be held directly or indirectly in a manner compatible with their personal investment activities and any applicable legal and regulatory requirements.

Elements of remuneration

In contrast to the position of executive directors' pay, in which an increasing element is performance-related, non-executive directors' pay comprises cash fees, paid monthly, with increments for positions of additional responsibility, reflecting additional workload and consequent potential liability. For all non-executive directors except the chairman, a fixed allowance is paid for transatlantic travel undertaken for the purpose of attending a board meeting. In addition, non-executive directors receive reimbursement of reasonable travel and related business expenses. No share or share option awards are made to any non-executive director in respect of service on the board. Non-executive directors have letters of appointment that recognize that, subject to the Articles of Association, their service is at the discretion of the shareholders. They submit themselves for election at the annual general meeting following their appointment and subsequently at intervals of no more than three years.

Non-executive directors' annual fee structure

The Articles provide that the remuneration paid to non-executive directors is determined by the board within limits set by shareholders. Fees payable to non-executive directors were reviewed during 2002. New and increased fees based on a comparable structure were approved by the board as from 1 July 2002. All fees are fixed and paid in pounds sterling. For conformity these are also reported in US dollars.

thousand	To 30 June 2002 $[a]	£	From 1 July 2002 $[a]	£
Chairman	420	280	585	390[b]
Deputy chairman	128	85	128	85[c]
Board member	68	45	98	65
Committee chairmanship fee	8	5	23	15
Transatlantic attendance allowance[d]	5	3	8	5

[a]Sterling payments converted at the average 2002 exchange rate of £1 = $1.50.
[b]The chairman is ineligible for committee chairmanship fees and transatlantic attendance allowance but has the use of a fully maintained office and a chauffeured car for company business.
[c]The deputy chairman receives a £20,000 increment on top of the standard board fee. In addition, this is supplemented by committee chairmanship fees and transatlantic attendance allowance. The deputy chairman is currently chairman of the Audit Committee. Prior to 1 July 2002, the deputy chairman received an all-inclusive fee of £85,000 and was ineligible for committee chairmanship fees and transatlantic attendance allowance.
[d]This allowance is payable to non-executive directors undertaking transatlantic travel for the purpose of attending a board meeting or board committee meeting.

Long-term incentives (residual)

The table in the right-hand column sets out the residual entitlements of non-executive directors who were formerly non-executive directors of Amoco Corporation under the Amoco Non-Employee Directors' Restricted Stock Plan.

Information subject to audit

Remuneration of non-executive directors

thousand	2002 $[a]	2002 £	2001 $[b]	2001 £
Current directors				
J H Bryan	**120**	**80**	82	57
E B Davis, Jr	**120**	**80**	82	57
Dr D S Julius	**95**	**63**	6	4
C F Knight	**95**	**63**	78	54
F A Maljers	**95**	**63**	78	54
Dr W E Massey	**135**	**90**	94	65
H M P Miles[c]	**95**	**63**	78	54
Sir Robin Nicholson[d]	**110**	**73**	83	57
Sir Ian Prosser	**147**	**98**	122	85
P D Sutherland	**503**	**335**	403	280
M H Wilson	**116**	**77**	86	60
Director leaving the board in 2002				
Sir Robert Wilson	**27**	**18**	73	51

[a]Sterling payments converted at the average 2002 exchange rate of £1 = $1.50.
[b]Sterling payments converted at the average 2001 exchange rate of £1 = $1.44.
[c]Also received £300 in 2001 ($432 at 2001 rate) and £600 in 2002 ($900 at 2002 rate) for serving as a director of BP Pension Trustees Limited.
[d]Also received £20,000 each year ($28,800 at 2001 rate and $30,000 at 2002 rate) for serving as the board's representative on the Technology Advisory Council.

Amoco Non-Employee Directors' Restricted Stock Plan

Non-executive directors of Amoco Corporation were allocated restricted stock in the Amoco Non-Employee Directors' Restricted Stock Plan by way of remuneration for their service on the board of Amoco Corporation prior to its merger with BP in 1998. On merger, interests in Amoco shares in the plan were converted into interests in BP ADSs. Under the terms of the plan, the restricted stock will vest upon the retirement of the non-executive director at age 70 or upon earlier retirement at the discretion of the board. Since the merger, no further entitlements have accrued to any director under the plan. These residual interests require disclosure under the Directors' Remuneration Report Regulations 2002 as interests in a long-term incentive scheme:

	Interest in BP ADSs 1 January 2002 and 31 December 2002[a]	Date on which director reaches age 70[b]
J H Bryan	5,546	5 October 2006
E B Davis, Jr	4,490	5 August 2014
F A Maljers	2,906	12 August 2003
Dr W E Massey	3,346	5 April 2008
M H Wilson	3,170	4 November 2007

[a]No awards were granted or vested and no awards lapsed during the year.
[b]For the purposes of the regulations, the date on which the director reaches age 70 is the end of the qualifying period. If the director retires prior to this date, the board may waive the restrictions.

Superannuation gratuities

In accordance with BP's long-standing practice, non-executive directors who retire from the board after at least six years' service are, at the time of their retirement, eligible for consideration for a superannuation gratuity. The board is authorized to make such payments under the company's Articles. The amount of the payment is determined at the board's discretion, having regard to the director's period of service as a director and other relevant factors. The board did not make any payment to Sir Robert Wilson, the only non-executive director retiring in 2002, in view of his limited length of service.

On the recommendation of the ad hoc committee on non-executive remuneration, during 2002 the board revised its policy with respect to such payments so that (i) non-executive directors appointed to the board after 1 July 2002 would not be eligible for consideration for such a payment, and (ii) non-executive directors in service at 1 July 2002 would remain eligible for consideration for a payment, but service after that date would not be taken into account by the board in considering the amount of any payment.

This directors' remuneration report was approved by the board and signed on its behalf by Miss Hanratty, company secretary, on 11 February 2003.

Shareholdings and Annual General Meeting

Substantial shareholdings

At the date of this report, the company has been notified that JPMorgan Chase Bank, as depositary for American Depositary Shares (ADSs), holds interests through its nominee, Guaranty Nominees Limited, in 6,518,514,934 ordinary shares (29.13% of the company's ordinary share capital). Included in this total is part of the holding of the Kuwait Investment Office (KIO). Either directly or through nominees, the KIO holds interests in 715,040,000 ordinary shares (3.20% of the company's ordinary share capital).

At the date of this report, the company has been notified of the following interests in preference shares: Co-operative Insurance Society Limited holds interests in 1,529,538 8% 1st preference shares (21.15% of that class) and 1,789,796 9% 2nd preference shares (32.70% of that class). Prudential plc holds interests in 528,150 8% 1st preference shares (7.30% of that class) and 644,450 9% 2nd preference shares (11.77% of that class). It should be noted that the total preference shares in issue comprise only 0.37% of the company's total issued nominal share capital, the rest being ordinary shares.

Annual General Meeting

The 2003 annual general meeting will be held on Thursday 24 April 2003 at 11.00 a.m. at the Royal Festival Hall, Belvedere Road, London SE1 8XX, UK. A separate notice convening the meeting is sent to shareholders with this report, together with an explanation of the items of special business to be considered at the meeting.

All resolutions of which notice has been given will be decided on a poll.

Ernst & Young LLP have expressed their willingness to continue in office as auditors and a resolution for their reappointment is included in the notice of the annual general meeting.

By order of the board
Judith C Hanratty
Secretary
11 February 2003

Further information

Administration

If you have any queries about the administration of shareholdings such as change of address, change of ownership, dividend payments, the dividend reinvestment plan or the ADS direct access plan, please contact the Registrar or ADS Depositary:

UK – Registrar's Office
The BP Registrar
Lloyds TSB Registrars
The Causeway, Worthing, West Sussex BN99 6DA
Telephone: +44 (0)121 415 7005
Freephone in UK: 0800 701107
Fax: +44 (0)1903 833371

USA – ADS Administration
JPMorgan Chase Bank
PO Box 43013, Providence, RI 02940-3013
Telephone: +1 781 575 3346
Toll-free in USA and Canada: +1 877 638 5672

Canada – ADS Administration
CIBC Mellon Trust Company, 199 Bay Street
Commerce Court West, Securities Level, Toronto, Ontario M5L 1G9
Telephone: +1 416 643 5500
Toll-free in Canada and the USA: +1 800 387 0825

Japan
The Mitsubishi Trust and Banking Corporation
7-7 Nishi-Ikebukuro 1-chome, Toshima-ku, Tokyo 171-8508
Telephone: +81 3 5391 7029
Fax: +81 3 5391 1911

Publications

Copies of *Annual Accounts 2002*, *Form 20-F*, *BP Environmental and Social Review 2002*, *BP Financial and Operating Information 1998-2002*, *BP Statistical Review of World Energy* and other BP publications may be obtained free of charge from the following sources:

USA and Canada
Toll-free: +1 800 638 5672
Fax: +1 630 821 3456
shareholderus@bp.com

UK and Rest of World
BP Distribution Services
International Distribution Centre
Crabtree Road, Thorpe
Egham, Surrey TW20 8RS, UK
Telephone: +44 (0)870 241 3269
Fax: +44 (0)870 240 5753
bpdistributionservices@bp.com

To elect to receive the full Directors' Report and Annual Accounts in place of summary financial statements for all future financial years, please write to the UK Registrar at the address on this page.

To receive your company documents (such as Annual Report and Notice of Meeting) electronically, please register at *www.bp.com/edelivery*

Internet
The BP website is at *www.bp.com*

Audio cassettes/CDs for visually impaired shareholders
Highlights from *Annual Report 2002* are available on audio cassette and CD. Copies may be obtained free of charge from the sources listed under 'Publications'.

Acknowledgements

Imagery
Most photography by BP Photographic Services
Photographers: James Bareham, Terry Beasley, Mike Ellis, Dean Freeman, Ben Gibson, Matt Harris, Ian Hunt, Levan Lagazidze, Mark Lever, Morrison Wulffraat, Fritz Timmer
Other imagery: Getty Images Inc.

Paper
The paper used for this report meets the strictest environmental standards set by the Nordic Swan Council and is fully recyclable. It is made at a mill accredited to ISO 14001. The pulp used to produce the paper is generated locally and bleached without the use of elemental chlorine.

Design and production
Designed and typeset by Pauffley, London
Printed in England by St Ives Burrups Limited
Printed in the USA by Sandy Alexander

Board of directors

Executive directors

1. The Lord Browne of Madingley, FREng
Group Chief Executive
Lord Browne (54) was appointed an executive director of BP in 1991 and group chief executive in 1995. He is a non-executive director of Goldman Sachs Group and Intel Corporation, and a trustee of the British Museum.

Member of the Nomination Committee

2. R L Olver
Deputy Group Chief Executive
Dick Olver (56) was appointed an executive director of BP in 1998, and deputy group chief executive in January 2003. He is a non-executive director of Reuters Group.

3. Dr D C Allen
Group Chief of Staff
David Allen (48) was appointed an executive director of BP in February 2003.

4. R F Chase
Senior Adviser to Group Chief Executive
Rodney Chase (59) was appointed an executive director of BP in 1992. He is a non-executive director of Computer Sciences Corporation, Diageo and Tesco. He is also a trustee of the Prince of Wales International Business Leaders Forum and a member of the executive board of the World Council for Sustainable Development.

5. Dr B E Grote
Chief Financial Officer
Byron Grote (54) was appointed an executive director of BP in 2000 and chief financial officer in November 2002.

6. Dr A B Hayward
Chief Executive, Exploration and Production
Tony Hayward (45) was appointed an executive director of BP in February 2003. He is a non-executive director of Corus Group.

7. J A Manzoni
Chief Executive, Refining and Marketing
John Manzoni (43) was appointed an executive director of BP in February 2003.

Non-executive directors

8. P D Sutherland, SC
Non-Executive Chairman
Peter Sutherland (56) rejoined BP's board in 1995, having previously been a non-executive director from 1990 to 1993, and was appointed chairman in 1997. He is non-executive chairman of Goldman Sachs International and a non-executive director of Telefonaktiebolaget LM Ericsson, Investor AB and The Royal Bank of Scotland Group.

Chairman of the Chairman's and Nomination Committees

9. Sir Ian Prosser
Non-Executive Deputy Chairman
Sir Ian (59) joined BP's board in 1997 and was appointed non-executive deputy chairman in 1999. He is chairman of Six Continents and a non-executive director of GlaxoSmithKline.

Member of the Chairman's and Remuneration Committees and chairman of the Audit Committee

10. J H Bryan
John Bryan (66) joined Amoco's board in 1982. He serves on the boards of Bank One Corporation, General Motors Corporation and Goldman Sachs. He retired as chairman of Sara Lee Corporation in 2001.

Member of the Chairman's and Audit Committees

11. E B Davis, Jr
Erroll B Davis, Jr (58) joined Amoco's board in 1991. He is chairman, president and chief executive officer of Alliant Energy. He is a non-executive director of PPG Industries and chairman of the Board of Trustees of Carnegie Mellon University.

Member of the Chairman's, Audit and Remuneration Committees

12. Dr D S Julius, CBE
DeAnne Julius (53) joined BP's board in 2001. From 1997 to 2001 she was a full-time member of the Monetary Policy Committee of the Bank of England. She is a non-executive director of the Court of the Bank of England, Lloyds TSB, Serco and Roche Holding.

Member of the Chairman's and Remuneration Committees

13. C F Knight
Charles Knight (67) joined BP's board in 1987. He is chairman of Emerson Electric and is a non-executive director of Anheuser-Busch, Morgan Stanley Dean Witter, SBC Communications and IBM.

Member of the Chairman's and Remuneration Committees

14. F A Maljers, KBE
Floris Maljers (69) joined Amoco's board in 1994. A member of the supervisory boards of SHV Holding and Vendex NV, he is chairman of the supervisory boards of KLM Royal Dutch Airlines, the Amsterdam Concertgebouw and Rotterdam School of Management, Erasmus University.

Member of the Chairman's and Ethics and Environment Assurance Committees

15. Dr W E Massey
Walter Massey (64) rejoined Amoco's board in 1993, having previously been a director from 1983 to 1991. He is president of Morehouse College, a non-executive director of Motorola, Bank of America and McDonald's Corporation and a member of President Bush's Council of Advisors on Science & Technology.

Member of the Chairman's Committee and chairman of the Ethics and Environment Assurance Committee

16. H M P Miles, OBE
Michael Miles (66) joined BP's board in 1994. He is chairman of Schroders and of Johnson Matthey.

Member of the Chairman's, Audit and Ethics and Environment Assurance Committees

17. Sir Robin Nicholson, FREng, FRS
Sir Robin (68) joined BP's board in 1987. He is a non-executive director of Rolls-Royce.

Member of the Chairman's Committee and chairman of the Remuneration Committee

18. M H Wilson
Michael Wilson (65) joined Amoco's board in 1993. He is president and chief executive officer of UBS Global Asset Management (Canada) and a non-executive director of Manufacturers Life Insurance Company and UBS Global Asset Management.

Member of the Chairman's, Audit and Ethics and Environment Assurance Committees

Changes to the board

Mr W D Ford retired as an executive director on 31 March 2002.
Sir Robert Wilson retired as a non-executive director on 18 April 2002. Prior to his retirement, he was a member of the Chairman's, Audit and Ethics and Environment Assurance Committees.
Dr J G S Buchanan retired as an executive director and chief financial officer on 21 November 2002.
Dr D C Allen was appointed an executive director on 1 February 2003.
Dr A B Hayward was appointed an executive director on 1 February 2003.
Mr J A Manzoni was appointed an executive director on 1 February 2003.
Mr R F Chase will retire as an executive director on 23 April 2003.

Company secretary

Judith Hanratty, OBE, (59) has been company secretary since 1994. She is a nominated member of the Council of Lloyd's of London and a member of the Lloyd's Franchise Board. She is also a non-executive director of Partnerships UK and Charles Taylor Consulting, and a member of the Competition Commission and the Takeover Panel. A barrister, she is chairman of The Commonwealth Institute and deputy chairman of the College of Law.

elevate expectations

ConocoPhillips

2002 Annual Report

Contents

ConocoPhillips At A Glance 2
A review of the company's global operations.

Letter to Shareholders 5
Chairman Archie Dunham and President and CEO Jim Mulva discuss the company's strategy for improving returns to shareholders.

An Interview with Jim Mulva 8
President and CEO Jim Mulva answers shareholders' questions.

Operating Review 10
ConocoPhillips' operating groups are capturing merger synergies while building on a portfolio of world-class assets.

Corporate Review 30
Corporate staffs are essential to helping ConocoPhillips achieve its objectives while supporting the company's values and purpose.

Financial Review 36

Directors and Officers 106

Glossary 108

Our Theme: Elevate Expectations

The PL19-3A wellhead platform rises high above the waters of China's Bohai Bay, where ConocoPhillips announced first production from the Peng Lai field in late 2002. Like the platform reaching skyward, ConocoPhillips seeks to elevate expectations for performance beyond what was possible before the merger. The company is pursuing a clear strategy to improve returns for its shareholders — by capturing merger-related synergies, selling billions of dollars of non-core assets, growing its Exploration and Production segment, and applying a disciplined approach to cost control, capital spending and debt reduction.

Highlights

	Millions of Dollars Except as Indicated		
	2002	2001	% Change
Financial			
Total revenues	**$57,224**	25,044	128
Income from continuing operations	**$ 714**	1,611	(56)
Net income (loss)	**$ (295)**	1,661	(118)
Per share of common stock — diluted			
Income from continuing operations	**$ 1.47**	5.46	(73)
Net income (loss)	**$ (.61)**	5.63	(111)
Net cash provided by operating activities from continuing operations	**$ 4,767**	3,529	35
Net cash provided by operating activities	**$ 4,969**	3,562	40
Capital expenditures and investments	**$ 4,388**	3,016	45
Total assets at year-end	**$76,836**	35,217	118
Total debt	**$19,766**	8,654	128
Mandatorily redeemable preferred securities of trust subsidiaries	**$ 350**	650	(46)
Other minority interests	**$ 651**	5	—
Common stockholders' equity	**$29,517**	14,340	106
Percent of total debt to capital*	**39%**	37	5
Common stockholders' equity per share (book value)	**$ 43.56**	37.52	16
Cash dividends per common share	**$ 1.48**	1.40	6
Closing stock price per common share	**$ 48.39**	60.26	(20)
Common shares outstanding at year-end (in thousands)	**677,570**	382,158	77
Average common shares outstanding (in thousands)			
Basic	**482,082**	292,964	65
Diluted	**485,505**	295,016	65
Employees at year-end (in thousands)	**57.3**	38.7	48

**Capital includes total debt, mandatorily redeemable preferred securities of trust subsidiaries, other minority interests and common stockholders' equity.*

	2002	2001	% Change
Operating			
U.S. crude oil production (MBD)	**371**	373	(1)
Worldwide crude oil production (MBD)*	**682**	563	21
U.S. natural gas production (MMCFD)	**1,103**	917	20
Worldwide natural gas production (MMCFD)*	**2,047**	1,335	53
Worldwide natural gas liquids production (MBD)	**46**	35	31
Worldwide Syncrude production (MBD)	**8**	—	—
Worldwide production on a barrel-of-oil-equivalent basis, including Syncrude (MBD)*	**1,077**	821	31
Natural gas liquids extracted — midstream (MBD)	**156**	120	30
Refinery crude oil throughput (MBD)	**1,813**	706	157
Refinery utilization rate (%)	**90**	94	(4)
U.S. automotive gasoline sales (MBD)**	**1,147**	465	147
U.S. distillates sales (MBD)**	**392**	170	131
Worldwide petroleum products sales (MBD)**	**2,258**	943	139
Ethylene production (MMlbs)*	**3,217**	3,291	(2)
Polyethylene production (MMlbs)*	**2,004**	1,956	2

**Includes ConocoPhillips' share of equity affiliates' production.*
***Excludes spot market sales.*

The ConocoPhillips merger was consummated on August 30, 2002, and used purchase accounting to recognize the fair value of Conoco Inc. assets and liabilities. Consequently, results for the year 2002 include eight months of activity for Phillips Petroleum Company and four months of activity for ConocoPhillips. Prior periods reflect only Phillips results.

Certain disclosures in this Annual Report may be considered "forward-looking" statements. These are made pursuant to "safe harbor" provisions of the Private Securities Litigation Reform Act of 1995. The "Cautionary Statement" in Management's Discussion and Analysis on page 58 should be read in conjunction with such statements.

"ConocoPhillips," "the company," "we" and "our" are used interchangeably in this report to refer to the businesses of ConocoPhillips and its consolidated subsidiaries. All numerical references to crude oil, natural gas or natural gas liquids production volumes refer to production from proved reserves.

ConocoPhillips At A Glance

Our Purpose: *Use Our Pioneering Spirit to Responsibly Deliver Energy to the World*

Who We Are

ConocoPhillips is an international, integrated energy company. It is the third-largest integrated energy company in the United States, based on market capitalization, oil and gas proved reserves and production; and the largest refiner in the country. Worldwide, it is the sixth-largest publicly owned energy company, based on oil and gas reserves, and the fifth-largest refiner.

ConocoPhillips is known worldwide for its technological expertise in deepwater exploration and production, reservoir management and exploitation, 3-D seismic technology, high-grade petroleum coke upgrading and sulfur removal.

Headquartered in Houston, Texas, ConocoPhillips operates in more than 40 countries. The company has approximately 57,000 employees worldwide and assets of $77 billion. ConocoPhillips stock is listed on the New York Stock Exchange under the symbol “COP.”

Our Businesses

The company has four core activities worldwide:

- Petroleum exploration and production.
- Petroleum refining, marketing, supply and transportation.
- Natural gas gathering, processing and marketing, including a 30.3 percent interest in Duke Energy Field Services, LLC.
- Chemicals and plastics production and distribution through a 50 percent interest in Chevron Phillips Chemical Company LLC.

In addition, the company is investing in several emerging businesses — fuels technology, gas-to-liquids, power generation and emerging technologies — that provide current and potential future growth opportunities.

Exploration and Production (E&P)

Profile: Explores for and produces crude oil, natural gas and natural gas liquids on a worldwide basis. Also mines oil sands to produce Syncrude. A key strategy is to accelerate growth by developing legacy assets — very large oil and gas developments that can provide strong financial returns over long periods of time — through exploration, exploitation, redevelopments and acquisitions; and by focusing exploration on larger, lower-risk areas.

Operations: At year-end 2002, ConocoPhillips held a combined 102 million net developed and undeveloped acres in 29 countries, and produced hydrocarbons in 14. Crude oil production in 2002 averaged 682,000 barrels per day (BPD), gas production averaged 2.05 billion cubic feet per day and natural gas liquids production averaged 46,000 BPD. Key regional focus areas include the North Slope of Alaska; Canada; offshore China; the Lower 48 United States, including the Gulf of Mexico; Kazakhstan; Nigeria; the North Sea; Southeast Asia; the Timor Sea; and Venezuela.

Strengths: Seismic imaging technology; deepwater exploration; reservoir management and exploitation; enhanced oil recovery; managing large offshore developments; operations in the North Sea, Arctic and other environmentally sensitive areas.

Competitors: Major integrated petroleum companies, including ExxonMobil, ChevronTexaco, BP, Shell and TotalFinaElf; independent exploration and production companies, including Apache, Burlington Resources and Devon Energy; and national oil companies.

Customers: Third-party refiners and processors, large industrial users and ConocoPhillips’ refining operations.

Refining and Marketing (R&M)

Profile: Refines crude oil and markets and transports petroleum products. ConocoPhillips is the largest refiner in the United States and the fifth-largest refiner in the world.

Operations: *Refining* — At year-end 2002, ConocoPhillips owned 12 U.S. refineries (excluding two refineries held for sale), owned or had an interest in five European refineries and had an interest in one refinery in Malaysia, totaling a combined net crude oil refining capacity of 2.6 million barrels of oil per day. *Marketing* — At year-end 2002, ConocoPhillips’ gasoline and distillates were sold through approximately 17,000 branded outlets in the United States, Europe and Southeast Asia. In the United States, products were primarily marketed under the Phillips 66, 76 and Conoco brands. In Europe and Southeast Asia, the company marketed primarily under the Jet and ProJET brands. ConocoPhillips also marketed lubricants, commercial fuels, aviation fuels and liquid petroleum gas. ConocoPhillips’ refined products sales were 2.3 million barrels per day in 2002. The company also participated in joint ventures that support the specialty products business. *Transportation* — R&M owned or had an interest in about 31,500 miles of pipeline systems in the United States at year-end 2002.

Strengths: Branded wholesale marketing; refining technologies; aviation gasoline sales; and refining capabilities.

Competitors: Major refiners and marketers in North America, Europe and Asia Pacific including ChevronTexaco, ExxonMobil, Shell, TotalFinaElf and BP; independent refiners/marketers, including Valero, Tesoro and Sunoco; and hypermarts such as Wal-Mart.

Customers: Independent marketers and the consuming public.

Midstream

Profile: Midstream consists of ConocoPhillips' 30.3 percent interest in Duke Energy Field Services, LLC (DEFS), as well as certain ConocoPhillips assets in the United States, Canada and Trinidad. Midstream gathers natural gas, extracts and sells the natural gas liquids (NGL) and sells the remaining (residue) gas. Headquartered in Denver, Colo., DEFS is one of the largest natural gas gatherers, NGL producers and NGL marketers in the United States.

Operations: At year-end 2002, DEFS' gathering and transmission systems included some 60,000 miles of pipelines, mainly in seven of the major U.S. gas regions, plus western Canada. DEFS also owned and operated, or owned an equity interest in 71 NGL extraction plants. Raw natural gas throughput averaged 7.4 billion cubic feet per day, and NGL extraction averaged 392,000 BPD in 2002. In addition to its interest in DEFS, ConocoPhillips owned or had an interest in an additional 13 NGL extraction plants at year-end 2002.

Strengths: Assets in major gas-producing regions; efficient, reliable low-cost operations; and critical mass for growth transactions.

Competitors: Williams, El Paso, BP, ExxonMobil, ChevronTexaco, ONEOK and Koch.

Customers: Primarily major and independent natural gas producers, local gas distribution companies, electrical utilities, industrial users and marketing companies. Among DEFS' customers for NGL are Chevron Phillips Chemical Company and ConocoPhillips' R&M operations.

Chemicals

Profile: ConocoPhillips participates in the chemicals sector through its 50 percent ownership of Chevron Phillips Chemical Company LLC (CPChem), a joint-venture company formed with Chevron (now ChevronTexaco) on July 1, 2000. Headquartered in The Woodlands, Texas, its major product lines include: olefins and polyolefins, including ethylene, polyethylene, normal alpha olefins and plastic pipe; aromatics and styrenics, including styrene, polystyrene, benzene, cyclohexane, paraxylene and K-Resin® styrene-butadiene copolymer; and specialty chemicals and plastics.

Operations: CPChem's major facilities in the United States are at Baytown, Borger, Conroe, La Porte, Orange, Pasadena, Port Arthur and Old Ocean, Texas; St. James, La.; Pascagoula, Miss.; and Marietta, Ohio. The company also has nine plastic pipe plants and one pipefittings plant in eight states, and a petrochemical complex in Puerto Rico. Major international facilities are in Belgium, China, Saudi Arabia, Singapore, South Korea and Qatar. CPChem also has a plastic pipe plant in Mexico.

Strengths: One of the world's largest producers of ethylene, polyethylene, styrene, alpha olefins, and one of the largest marketers of cyclohexane.

Competitors: Dow Chemical, ExxonMobil, BP, Equistar and Shell.

Customers: Primarily companies that produce industrial products and consumer goods.

Emerging Businesses

ConocoPhillips has four emerging businesses under development: fuels technology, natural gas-to-liquids technology, power generation and emerging technologies. These businesses are closely tied to the company's core operations and offer growth potential.

Fuels Technology: S Zorb™ is ConocoPhillips' proprietary technology for removing sulfur from gasoline and diesel streams during refining. The technology is proven to reduce sulfur content in fuels to levels well below allowable limits proposed by regulators in the United States and Europe. The technology has been licensed to five refiners worldwide, and ConocoPhillips plans to install the technology at several of its U.S. refineries.

Gas-to-Liquids: Commissioning of a gas-to-liquids demonstration plant will begin in 2003 at the Ponca City, Okla., refinery. Once the technology is proven, ConocoPhillips will be capable of building a commercial-scale plant. The company's new gas-to-liquids technology has the potential to convert stranded natural gas reserves in remote locations to liquids that can be economically transported to market.

Power Generation: ConocoPhillips is using creativity and innovation to access new high-growth markets for natural gas and electricity. By integrating power generation with ConocoPhillips' upstream and downstream businesses, the company is able to structure power projects — such as cogeneration — to provide maximum value for both ConocoPhillips and its customers.

Emerging Technologies: The emerging technologies portfolio includes a variety of business ventures and technical programs that are pioneering the future energy landscape, including renewable energy, advanced hydrocarbon processes, energy conversion technologies and hydrocarbon upgrading opportunities.

ConocoPhillips: A Global Competitor

Key Worldwide Operations

ConocoPhillips emerged in 2002 as a major global competitor, with operations on nearly every continent. The company has large oil and gas operations in Canada, China, Indonesia, Kazakhstan, Nigeria, the Timor Sea, the U.K. and Norwegian sectors of the North Sea, the United States, Venezuela and Vietnam. Alaska is the company's largest production center, producing 375,000 to 400,000 net barrels of oil equivalent per day. ConocoPhillips is the largest refiner in the United States with 12 refineries that supply motor fuels to 14,000 branded outlets. The company also is a strong competitor in the European refining and marketing sector, with approximately 3,000 retail outlets and interests in five refineries. In addition, ConocoPhillips has an interest in a refinery in Malaysia and a small marketing presence in Southeast Asia.

North America
United States - E,P,R,M
Canada - E,P

South America
Ecuador - P
Venezuela - E,P
Brazil - E

Europe
Austria - M
Azerbaijan - E
Belgium - M
Czech Republic - R,M
Denmark - E,M
Finland - M
Germany - R,M
Hungary - M
Ireland - R
Kazakhstan - E
Luxembourg - M
Norway - E,P, M
Poland - M
Russia - E,P
Slovakia - M
Switzerland - M
Sweden - M
Turkey - M
United Kingdom - E,P,R,M

Africa
Nigeria - E,P
Cameroon - E
Angola - E

Middle East
Dubai - P

Asia
China - E,P
Vietnam - E,P
Malaysia - E,R,M
Indonesia - E,P
East Timor - E,P
Thailand - M

Australia - E,P

KEY:
E - Exploration
P - Production
R - Refining
M - Marketing

Elevating Expectations for Our Shareholders and Ourselves

To Our Shareholders:

In 2002, we created an exciting new company: ConocoPhillips. We are the third-largest energy company in the United States, the sixth-largest publicly held energy company in the world in terms of crude oil and natural gas proved reserves, and the fifth-largest global refiner. We are fully integrated, participating in every phase of the energy business — from finding and producing crude oil and natural gas to refining these raw materials and marketing fuels, chemicals and other products. The scope and size of our asset and investment portfolio makes ConocoPhillips a strong competitor around the world.

However, size does not guarantee success. We must elevate expectations for ourselves — we must perform at a higher level to generate returns for our shareholders that are competitive with the best companies in the world. How will we do this? We will use a disciplined approach to manage capital spending, operating costs and our balance sheet. We will utilize our assets and technology to their maximum potential. Furthermore, the "can do" spirit of our employees will make ConocoPhillips a top performer in every aspect of our business.

Upstream, we have a portfolio of assets and investment alternatives that create many opportunities. While the company is active on nearly every continent in the world, the bulk of our upstream operations are located in regions that are stable and secure. More than 75 percent of our assets are in North America and the North Sea. This allows us the flexibility to reach into all areas of the world while maintaining a balanced risk portfolio.

Downstream, ConocoPhillips is one of the largest refiners and marketers in the United States and historically has been a top performer in Europe. In the United States, ConocoPhillips has 12 refineries and 14,000 branded outlets. Elsewhere in the world, the company has six refineries and 3,000 outlets in 17 countries.

Midstream, ConocoPhillips owns 30.3 percent of the Duke Energy Field Services (DEFS) joint venture, the largest natural gas liquids producer in the United States. ConocoPhillips also owns additional midstream assets outside of DEFS.

The Commercial organization allows ConocoPhillips to realize the maximum benefits of integration, enabling the company to optimize the value of its equity crude oil, natural gas and other commodities, as well as lowering crude oil feedstock and energy costs for its refineries. Commercial also ensures we provide a cost effective, reliable supply of products to our many customers around the world.

Archie W. Dunham, *Chairman and*
J.J. Mulva, *President and Chief Executive Officer*

The company participates in the chemicals industry through our 50 percent ownership of Chevron Phillips Chemical Company.

In the Emerging Businesses segment, the company is a leader in fuel desulfurization and is seeking to commercialize other exciting new energy breakthroughs. Our proprietary technologies support our existing businesses and have excellent potential for contributing to the future profits of our company.

Above all, we have the corporate values and the human capital — the skilled, dedicated workers and a talented management team — that are essential to the success of any major enterprise.

A Transition Year

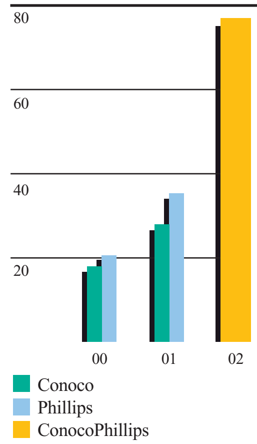
The year 2002 was a transition year. The transformation to a new company with a breadth of operations and asset base unlike anything in the past makes comparisons with the past less meaningful. For example, ConocoPhillips ended this year with $77 billion of assets. Just a few years ago, in 1999, Phillips Petroleum had $15 billion of assets and Conoco had $16 billion of assets. As a result, we will not be making many comparisons with the past like we may have done before.

In addition, this past year also was a year of significant changes in the regulatory environment for our financial reporting. In order to increase transparency of information and fully support improved communication to the investing community, the company has implemented in this annual report the early adoption of the new standard released by the U.S. Securities and Exchange Commission related to the use of financial measures that are different than financial measures under generally accepted accounting principles. As a result, you will not see a "net operating income" financial measure, which historically adjusted net income to exclude certain special items as defined by management.

For 2002, the company's income from continuing operations was $714 million, or $1.47 per share. This amount was affected by merger-related costs totaling $557 million, after-tax, as well as other factors. Discontinued operations included $1 billion of impairments and loss provisions related to the planned sale of marketing assets — part of our long-range strategy to improve the company's returns. As a result, the company had a net loss of $295 million, or $0.61 per share, for the year.

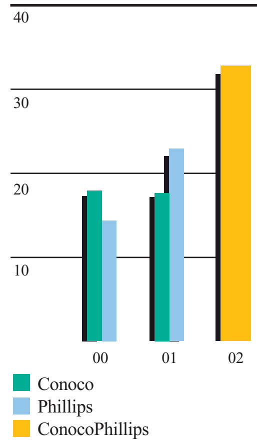
The task ahead is to leverage our considerable strengths to achieve the best possible returns for our shareholders. Over the next several years, we expect to improve ConocoPhillips' return on capital employed (ROCE), assuming midcycle returns and margins, to a more competitive level. Over time, we expect to achieve returns comparable with the very best performers in our industry. Consistent delivery of good operating performance and improved returns will permit increasing and sustained shareholder value creation.

Total Assets (Billions of Dollars)



The increase in total assets over the past three years reflects the rapid growth both companies experienced prior to the merger, as well as an increased asset base as a result of the merger. The acquisition of ARCO Alaska assets in 2000, and the acquisitions of Tosco and Gulf Canada in 2001 significantly increased each company's asset base. The merger also increased total assets because the book values of a substantial portion of Conoco's assets were revised upward to fair values as a result of purchase accounting rules.

Market Capitalization (Billions of Dollars)



ConocoPhillips' market capitalization exceeded $30 billion at the end of 2002, ranking the company as the third-largest oil and gas company in the United States. The company had 677.6 million common shares outstanding at Dec. 31, 2002, with a year-end closing stock price of $48.39.

Financial Discipline

In terms of financial management, we will apply a high degree of discipline to improve returns. We want discipline in our cost structure, our capital program and in improving the balance sheet. In particular, we want to reduce our debt-to-capital ratio from the present 39 percent to the mid-30 percent range over the next few years.

Reducing debt should result in a stronger share price. It also will better enable us to weather downturns in energy prices and other factors we can't control, and provide better ability to seize new opportunities as they arise.

Discipline means accountability in terms of cost control, completing projects on time and within budget, and adding real value for every dollar we invest. We intend to closely monitor our processes. Discipline will go a long way toward improving the company's financial performance and making our ROCE more competitive with the largest companies in the industry.

Improving Upstream Returns

We plan to grow the upstream business, which has historically produced higher returns, to 65 percent of the company's total asset base, excluding goodwill, compared with the current level of 57 percent. We will do this primarily through organic growth, investing 75 percent of our overall 2003 capital budget in the Exploration and Production segment of our business. Capital will be spent on increasing production and proved reserves, and building legacy assets — large oil and gas developments that can generate strong financial returns over long periods of time through a variety of changing price and operational environments. For example, in the Asia Pacific region, we recently began production from the Peng Lai field in China's Bohai Bay, and the first phase of the Bayu-Undan natural gas and natural gas liquids development in the Timor Sea is expected to begin production in 2004.

At the same time we are pursuing newer legacy projects, we expect to continue to maintain production levels in our mature legacy assets in our current core areas. In Europe, we are commencing development of Clair, the largest undeveloped oil field in the United Kingdom. We have prepared a plan for growing production from the Greater Ekofisk Area. And in Alaska, we are developing the heavy-oil West Sak field to help maintain production levels there.

Finally, we plan to spend about $750 million in 2003 on exploration around the world. This spending includes capital, as well as geological and geophysical expenses, to improve our future exploration prospects and to drill existing ones. Our principal drilling target areas this year include the Norwegian Sea, the Caspian Sea, the deepwater Gulf of Mexico and the Niger Delta.

Rationalization of Assets

U.S. Federal Trade Commission approval of the merger required the divestiture of certain assets. Beyond that, we are re-evaluating our assets across the board with a view toward divesting those that don't fit our portfolio or that we're not sure can perform to our expectations. We plan to sell $3 billion to $4 billion or more of assets by the end of 2004. We will apply the proceeds to our capital program, debt reduction and the reduction of certain lease obligations.

Synergies

When the merger was announced, we told the financial community that we expected to realize $750 million a year in synergies. We have since raised our synergy target to $1.25 billion a year by the end of 2003.

We are confident of meeting this higher goal because of the complementary nature of the operations. In some cases, the respective operations of the merged companies dovetailed with each other, as in the North Sea, where ConocoPhillips combines the larger asset base that Conoco had in the United Kingdom with the larger asset base that Phillips enjoyed in Norway. In other cases, we were already working virtually side-by-side. In Venezuela, for example, we have identified synergies from capital savings, operating efficiencies and elimination of the marketing overlap between our two adjacent heavy-oil projects, Hamaca and Petrozuata.

We expect to secure similar efficiencies on a company-wide basis. Duplicate offices and positions are being eliminated, and capital budgets have been combined and streamlined. We are applying best practices across-the-board to realize further savings. We have an improved procurement process that enables us to get the most competitive prices when purchasing materials and supplies. The Commercial organization will extract significant synergies through the purchase and sale of crude oil, refined products, natural gas, gas liquids and power.

Excellence in Technology

The merger of Conoco and Phillips combined two recognized leaders in technology, and we expect our continued efforts in this area to give us a competitive edge.

Upstream, our advanced technology enables us to explore for and produce oil and gas in deep water. The Magnolia field in the Gulf of Mexico is being developed in 4,700 feet of water using a tension-leg platform — a record depth for this type of facility. We have a proven liquefied natural gas technology and are developing a promising new technology to convert natural gas to liquids. These technologies could open new opportunities for us to commercialize stranded gas reserves.

Downstream, ConocoPhillips has made advances such as our alkylation technology and our S Zorb™ Sulfur Removal Technology. Both of these technologies will help us provide the world with cleaner fuels. In addition, our coking technology helps us lower our crude oil costs, a crucial driver for our long-term refining success.

Corporate Ethics and Values

The recent and highly publicized transgressions of a few large corporations have heightened public concern over corporate ethics. ConocoPhillips is committed to the highest expectations for integrity. We have in place the internal controls and the oversight to make sure that we have accounting integrity and full, transparent disclosure.

As our purpose states, our new company will "use our pioneering spirit to responsibly deliver energy to the world." This commitment, and our values, what we call our SPIRIT of Performance — Safety, People, Integrity, Responsibility, Innovation and Teamwork — are the watchwords that guide us.

The Year Ahead

As we begin 2003, we face a weak global economy, volatile energy prices and the potential for conflict in the Middle East. We are keeping a vigilant watch on all these situations, our greatest concern being the safety of our employees around the world.

In spite of these uncertainties, we are encouraged by our plan for improving returns in 2003 and beyond. We are making good progress and are pleased with the results thus far. Our early success is due to the spirit and commitment of dedicated employees. And yet, we have only just begun to capture the value of the opportunities that our new company can create. We have elevated our expectations, and our best performance is yet to come.

Archie W. Dunham
Chairman

J.J. Mulva
President and
Chief Executive Officer

March 24, 2003

An Interview with CEO Jim Mulva

Q ***How is the merger transition going?***

We were really well organized by the time we closed on the merger. When day one arrived, key policies and procedures were in place, including safety systems; the compensation programs were determined; and everyone in the company could communicate with each other. The top six levels of management and employees were in place and knew what they needed to do. Within one or two weeks all our customers had been notified and knew who their marketing representatives were. We saw the results of these preparations with strong income from continuing operations in the fourth quarter, our first full quarter as a new company.

Since day one, we've put together our strategic plan for the next five years. We're focused on executing our strategy, capturing synergies, operating well, and identifying and, in some cases, divesting assets that are no longer of strategic importance. I'm really pleased with the progress we've made since closing the merger.

We're starting to see a new culture emerge. We've been trying to get away from saying we'll take the best of this and the best of that, and cutting and pasting. Instead, we're making the tough decisions and moving on with the new company. Our core values — the SPIRIT of Performance — provide a sturdy framework upon which our new culture can further develop. Change is difficult for some people. But it's clear we know where we're going and how we're going to get there. The challenge now is developing a passion within everyone to work together to achieve common goals, and we're seeing that start to happen.

Q ***How will ConocoPhillips distinguish itself from the rest of the industry?***

We are uniquely positioned to compete with the best-performing companies in the industry and I'm excited about the opportunities that lie ahead for ConocoPhillips. When I look at the rest of the industry, I ask, "Are the super majors going to be able to grow like they have in the past?" I don't think they can.

However, ConocoPhillips' major opportunities still lie ahead. We still have synergies to capture; the largest companies have already completed their synergy capture as a result of transactions, acquisitions or mergers. We have in front of us the optimization of our portfolio and improvement of our returns. We also have ahead the improvement of our balance sheet, which we know how to do and will do. Looking at our upstream portfolio and the relationship of reserves to production, we have one of the best positions in the entire industry and we have some

J.J. Mulva, *President and Chief Executive Officer*

upside potential with projects like the Mackenzie Delta in Canada and Kashagan in the Caspian Sea. We have a good mix of short-, medium- and long-term opportunities.

We're a big company and we can compete with the largest companies in the industry for substantial projects, but we're not so large that big projects and significant discoveries don't have an impact. The largest companies must have many large projects to see any significant difference in earnings. One large project is still enough to significantly impact our earnings.

As we do what we've said we'll do — capture synergies, build long-term relationships, control costs, optimize capital spending, improve the portfolio and execute our growth programs — we can close the gap between us and our strongest competitors on return on capital employed and drive a much stronger share price. Our management team has the know-how, the commitment and the capability to deliver.

Q ***How will you improve returns when production is declining?***

Right now, our production is declining as we rationalize our portfolio to ensure we have the assets we want for the long term. As we continue to high-grade the portfolio and sell non-strategic assets over the near term, we will lose production. We are positioning our portfolio in 2003, then from 2003 to 2005 we expect our production to increase as some of our substantial developments come online, like the Bayu-Undan field in the Timor Sea and the Magnolia field in the Gulf of Mexico.

Q ***What is the political risk profile for ConocoPhillips?***

A majority of our assets and production is based in stable areas such as North America and the North Sea. Approximately 80 percent of our production comes from Organization for Economic Cooperation and Development member countries. However, as one of the largest foreign oil companies operating in Venezuela, we felt the effects of the general labor strike that took place there. Our production was halted in December after the strike began and has since come back online, but at lower levels than before the strike. Our Commercial group was successful in acquiring alternate feedstock supplies for our Lake Charles, La., and Sweeny, Texas, refineries that normally process Venezuelan crude oil.

We also have interests in the Middle East and Indonesia. We hope to become a bigger player in the Middle East through our participation in Core Ventures 1 and 3 of the Kingdom of Saudi Arabia's Natural Gas Initiative.

Q ***How can shareholders be assured that ConocoPhillips' finances and accounting practices are sound?***

It is the company's policy that its financial disclosures be accurate and complete, made on a timely basis and fairly present the company's financial condition, results of operations and cash flows. To assist in fulfilling this responsibility, we established a Disclosure Committee this year comprised of members of senior management and chaired jointly by the chief financial officer and the general counsel. The committee establishes and monitors the company's disclosure controls and procedures, reviewing and supervising the company's reports to the U.S. Securities and Exchange Commission (SEC), financial press releases and presentations to the investment community. I periodically meet with the committee to discuss the company's SEC filings and the certifications that have to be filed with them.

Q ***What are the criteria for divesting assets?***

On the upstream side, we target mature assets with higher costs and limited upside potential, and investment opportunities that do not meet our finding and development cost metrics or our return criteria. Those assets will have difficulty attracting capital funding, and are likely worth more to another company that will accept lower returns and fully develop the properties. We also consider whether we have critical mass or other competitive advantages that will allow us to be the low-cost producer in an area. If an asset does not have a competitive cost structure and does not have development potential at acceptable returns, it should be sold, with the proceeds used to pay down debt or reinvested in higher-return projects. We've already divested some of our lower-performing Exploration and Production assets in Canada and the Netherlands, and further upgrading of our upstream portfolio is ongoing.

Downstream, our asset divestiture program for 2003 is focused on retail assets. Retail gasoline and convenience store sales is a competitive business, with lower returns, and we would like to redeploy capital from this segment into higher returning upstream assets, while continuing to efficiently run our refining network and the wholesale channel of trade.

Q ***What are your plans for Midstream?***

We believe strongly in the benefits of integration, and we like our joint-venture position in Duke Energy Field Services, LLC (DEFS). Conoco brought midstream assets into the merger in some of the same areas where DEFS operates. We do not have an optimum midstream structure today. We have an opportunity to improve our midstream position, but there is no requirement to get out of either business or to put any assets into DEFS. We have complete flexibility in this situation and we are evaluating how we can better jointly work this midstream position to improve returns.

Q ***What's next for ConocoPhillips? Are there any more major acquisitions, mergers or joint ventures on the horizon?***

We do not need to do any significant acquisitions or transactions to enable us to be competitive with the largest companies in the industry. Do we have a lot of work to do? Yes. Can we improve our performance? Yes. But a large transaction is not necessary to rebalance our portfolio or to accomplish our objectives. That's not to say that if the right opportunity came along we wouldn't take a look at it, but we don't feel we're required to do something else to be competitive. It is important that we continue to capture the full value of past acquisitions and joint ventures, but more importantly, we need to capture the full value of the merger of Conoco and Phillips.

operating review

Sprays of water from a tugboat punctuate a milestone for the Bayu-Undan development — the completion and tow out of the first wellhead platform. The project is just one example of ConocoPhillips' ability to manage large, technically complex crude oil and natural gas developments. Located in the Timor Sea, Phase I production from Bayu-Undan is expected to begin in 2004 and average 32,900 net barrels of condensate and liquefied petroleum gas per day.

From the Timor Sea to New Jersey, ConocoPhillips' operations span the globe and the full scope of the energy industry. The company's business units are pursuing different strategies to achieve the same goal: stronger financial returns. Upstream, the company is building on a foundation of large, profitable crude oil and natural gas projects. Downstream, the company is focused on operating efficiently to squeeze the maximum value from every barrel of oil it processes and markets.

Exploration and Production

Pursuing Legacy Assets and Lower Costs

Exploration and Production's (E&P) strategy for improving returns is focused on developing legacy assets while applying a disciplined approach to costs, capital spending and portfolio management.

"Legacy assets are large oil and gas projects that can generate strong returns over 10 to 20 years or more and have the potential to generate new opportunities," explains Bill Berry, executive vice president of E&P.

The focus on large, profitable and sustainable assets will help lower costs, as well as guide the company's capital spending decisions. ConocoPhillips already has begun evaluating its E&P portfolio and has been divesting the smaller, nonstrategic assets. At year-end 2002, E&P had completed more than $600 million of its goal of $1.5 billion to $2 billion worth of asset sales by the conclusion of 2003.

In addition to its portfolio of legacy assets, ConocoPhillips is pursuing several exploration opportunities around the world.

Most of ConocoPhillips' exploration resources are committed to large, low- to medium-risk opportunities in proven and emerging exploration plays such as the Norwegian Sea, Caspian Sea, deepwater Gulf of Mexico and Niger Delta. In addition, the company continues to fund the best opportunities near its existing, high-value fields, and a limited number of high-value, higher-risk opportunities in frontier basins.

"We're developing a stronger, more focused portfolio going forward — one that is better positioned in key areas with a more consistent delivery," says Berry.

Global Operations Produce Results, Additional Opportunities

The Americas

In North America, the company's portfolio stretches from Alaska, where it is a major producer, through Canada to Texas and the deepwater Gulf of Mexico. In South America, the company has a significant presence in Venezuela.

W.B. Berry, *Executive Vice President, Exploration and Production*

Alaska Maintains Production, Keeps Costs Flat

ConocoPhillips' objective in Alaska is to maintain net production between 375,000 and 400,000 barrels of oil equivalent per day (BOEPD) while keeping production costs flat per barrel. "Maintaining flat operating costs isn't easy, but we achieved it in 2002, and we'll continue pursuing it as our goal in 2003," says Kevin Meyers, president of ConocoPhillips Alaska.

To maintain production, the company plans to enhance recovery in the three large, existing production areas on the North Slope — Prudhoe Bay, Kuparuk and the Western North Slope. Focused exploration drilling and further development of satellites near existing fields also are expected to help maintain production.

Prudhoe Bay has the largest reserve base and is the most mature of the three North Slope production areas. Net production from the Greater Prudhoe Bay Area in 2002 averaged 189,000 BOEPD. "Our challenge at Prudhoe Bay is to manage production decline and costs as the area ages," says Meyers.

Development of new satellite fields and the heavy-oil West Sak field will sustain production from the Greater Kuparuk Area. The Palm exploration discovery, which is being developed as an extension of the Kuparuk field, began production in November at a net rate of 6,000 barrels of oil per day (BOPD) through the end of 2002. The Greater Kuparuk Area includes four company-operated satellite fields, with net production of 104,000 BOEPD during 2002.

The Alpine field and five potential satellites drive growth in the Western North Slope area. ConocoPhillips expects to sanction the first expansion of the Alpine facilities in early 2003. In 2002, net production from Alpine was 63,000 BOPD.

The company also operates in the Cook Inlet, where net natural gas production was 166 million cubic feet per day (MMCFD) in 2002.

Polar Tankers Inc., a ConocoPhillips wholly owned subsidiary, operates a fleet of five vessels used to transport the company's Alaska crude oil production to refineries on the U.S. West Coast and Hawaii. The double-hulled crude oil tanker *Polar Resolution* was brought into service in 2002, joining the *Polar Endeavour* tanker that began service in 2001. Three more Endeavour Class double-hulled tankers are scheduled to join the fleet over the next three years.

Exploration geologist Bob Swenson examines rocks for clues that could lead to a new crude oil or natural gas discovery on Alaska's North Slope. Years of data collection may take place before the company determines an area could be a potential source of hydrocarbons and begins exploration drilling.

Company Pursuing Arctic Gas Developments

ConocoPhillips and its co-venturers are studying the economic viability of two projects that could transport Arctic natural gas to markets in North America. One project would originate in Canada's Mackenzie Delta and the other would bring gas from Alaska's North Slope. "We believe there will be a sufficient supply gap in the North American gas market to support both projects," says Berry.

ConocoPhillips and its co-venturers expect to file a preliminary information package for the Mackenzie Delta project with regulators in early 2003. Both federal enabling and fiscal legislation on the Alaska project are being pursued.

Focusing on Value in Canada

In Canada, ConocoPhillips is shifting from short-life, high-decline fields to longer-life, low-decline fields in the conventional basin, oil sands and Mackenzie Delta.

Development is continuing on schedule for the Surmont and Syncrude oil sands projects, as well as the Parsons Lake gas project in the Mackenzie Delta. "We have to do a lot of things right to be successful in Canada," says Henry Sykes, *ConocoPhillips is planning future growth in the North Sea around two key legacy assets: the Britannia gas field (below) and the Greater Ekofisk Area crude oil and natural gas development. The merger combined Conoco's and Phillips' interests in Britannia, giving ConocoPhillips a 58.7 percent interest.*

president of ConocoPhillips Canada. "We're focused on value, not volume. We plan to reduce our operating costs significantly and sell more than $300 million of our nonstrategic conventional properties."

Following the merger, net production from Canada averaged 89,000 barrels of liquids per day (including Syncrude) and 468 MMCFD of natural gas.

Lower 48: Legacy in Onshore Gas, Future in Deepwater

ConocoPhillips has a legacy position in Lower 48 natural gas production, with daily net production at year-end of approximately 1.4 billion cubic feet primarily from four areas: San Juan Basin, Texas Panhandle, Permian Basin and South Texas.

"Our strategy is to efficiently exploit the company's low-cost onshore leasehold position in the Lower 48," says Jim McColgin, president of U.S. Lower 48 and Latin America. "However, as production declines onshore, ConocoPhillips is looking to the deepwater Gulf of Mexico for future growth."

At year-end, the company held interests in 391 blocks in the Gulf of Mexico, and exploration drilling was under way in several blocks. In addition to exploration drilling, development drilling is ongoing in the Magnolia and Princess fields, and appraisal drilling is under way on the K2 discovery.

ConocoPhillips has a 75 percent interest in and is the operator of the Magnolia field, expected to come online in late 2004. A tension-leg platform will produce oil and natural gas from the field in nearly 4,700 feet of water — a record depth for this type of floating structure.

ConocoPhillips has a 16 percent interest in Princess, a low-cost subsea development that produces through facilities in the nearby Ursa field. Princess came onstream in 2002 and will achieve peak net production of 6,500 BOEPD by 2004.

The company has a nonoperated interest of 18.2 percent in the K2 field. Discovered in 1999, the field is under appraisal.

Pursuing Production in Venezuela's Orinoco Oil Belt and Offshore

ConocoPhillips has a sizeable ownership position in two of the four heavy-oil projects in Venezuela's Orinoco Oil Belt — Petrozuata and Hamaca — as well as a promising discovery located offshore.

A national labor strike temporarily shut down Petrozuata and Hamaca operations from December into February. Prior to the shutdown, combined net production from the projects was approximately 78,000 BOPD. Both projects resumed limited operations in February.

Petrozuata, a joint venture with Petroleos de Venezuela S.A. (PDVSA), began production in 1998. Hamaca, a joint venture with PDVSA and ChevronTexaco, began production in 2001 and is expected to increase its net production to 60,000 BOPD after construction of the upgrader facility is completed in late 2004. ConocoPhillips is evaluating the option to add a second upgrader — a move that could potentially double Hamaca's production.

Offshore Venezuela, ConocoPhillips is pursuing the development of the Corocoro field in the Gulf of Paria. Full government approval of the project is expected in 2003, with the first phase of production expected to begin in 2005. Two exploration wells are planned to assess additional opportunities in the Gulf of Paria in 2003.

Europe, Russia and Caspian

In Europe, ConocoPhillips' largest asset concentration is located in the North Sea. Elsewhere in the region, the company looks to the Russian Arctic and the Caspian Sea for future production growth.

Legacy Assets Anchor North Sea Production

While the North Sea is a mature area, ConocoPhillips expects to grow production around its largest North Sea legacy assets: the Britannia gas condensate field in the U.K. and the Greater Ekofisk Area in Norway.

"Britannia and Ekofisk provide a significant production base that will allow us to capture new growth opportunities in the North Sea," says Steve Theede, president of Europe, Russia and Caspian. "Both have substantial proved reserves and production life remaining. We expect North Sea production to increase through a combination of new opportunities, enhanced recovery at Ekofisk and new Britannia satellites."

Net production in 2002 from the Greater Ekofisk Area in the Norwegian North Sea increased to 127,000 barrels of liquids per day and 133 MMCFD of natural gas. An optimization plan for the Ekofisk field was submitted for review to the Norwegian government in December. ConocoPhillips has a 35.11 percent interest in Ekofisk.

In December, cumulative gross gas production from the Britannia field in the U.K. North Sea reached 1 trillion cubic feet since the field's startup in 1998. The company is assessing the development of the Britannia satellite fields Callanish and Brodgar, which could come online as early as 2006. ConocoPhillips has a 58.7 percent interest in Britannia.

Development of the Clair field continues, with the first phase of production expected in 2004. Clair is located on the U.K. continental shelf and has net proved reserves of 24 million barrels of petroleum liquids.

In Vietnam, ConocoPhillips is a major acreage holder with more than 3 million net acres under license. The company installed two new wellhead platforms at the Rang Dong field (above) in 2002, increasing field production by 80 percent.

Two of the five satellites in the Caister Murdoch System III natural gas development in the U.K. North Sea began producing in 2002. The Hawksley field came onstream in September and the Murdoch K field followed in December. Peak net production from the two fields was 175 MMCFD of gas at year-end.

The Jade field in the U.K. North Sea came onstream in February 2002 and reached peak production in July. Net production was 62 MMCFD of gas and 5,200 BOPD at the end of 2002.

In 2002, ConocoPhillips increased its interest from 18.3 percent to 24.3 percent in the Heidrun oil and natural gas field offshore Norway in the Norwegian Sea.

Russian Satellite Field Comes Onstream

ConocoPhillips, through its 50 percent interest in the Polar Lights joint venture, produces from two fields in the Timan-Pechora region — one of Russia's major hydrocarbon basins. The Ardalin field came onstream in 1994, and a satellite field — Oshkotyn — began production in June 2002. Net production from the joint venture was 13,500 BOPD for the last four months of 2002. The company also is pursuing other development opportunities in the Timan-Pechora region.

Kashagan Discovery Declared Commercial

An asset of world-class dimensions, the Kashagan discovery in the Caspian Sea was declared commercial in June 2002. An active exploration program continues while the joint-venture companies pursue approval of the initial phase of development. ConocoPhillips has an 8.33 percent interest.

A second discovery was made in the Caspian Sea near the Kashagan field in October. The Kalamkas-1 discovery was the first exploration well on the Kalamkas prospect. Evaluation of this discovery is under way.

Asia Pacific

In the Asia Pacific region, ConocoPhillips has an excellent inventory of large, long-lived grassroots development projects, as well as exploration positions in eight countries.

First Oil from China's Bohai Bay

Oil production from the Peng Lai 19-3 field in China's Bohai Bay began in late December. Phase I development utilizes one 24-slot wellhead platform and a floating production, storage and offloading facility. By the end of January 2003, the field was producing at a net rate of 8,200 BOPD. Net production is expected to reach 17,500 to 20,000 BOPD.

Phase II development plans are under way and will incorporate knowledge gained from the Phase I drilling and production results. Exploration drilling in the Bohai block will continue in 2003.

Gas Key to Growth in Indonesia

ConocoPhillips' growth in Indonesia is anchored by five major long-term gas contracts, two from its fields in Block B of the Natuna Sea and three from its fields onshore Sumatra.

Gas deliveries from Block B to Singapore began in 2001, while deliveries to Malaysia began in August 2002. Development of the Belanak field is under way, with first production expected in late 2004. Belanak will support the Block B gas contracts, as well as increase oil and gas liquids production.

ConocoPhillips will begin delivering gas from Sumatra to Singapore in late 2003, following the completion of a pipeline. Ongoing development of the Suban field in South Sumatra will provide for additional gas contracts.

Net production in Indonesia averaged 14,700 BOPD and 217 MMCFD of gas for the last four months of 2002.

Growth Continues in Vietnam

ConocoPhillips holds a significant working interest in six blocks and a pipeline offshore Vietnam. Two new wellhead platforms in the Rang Dong field boosted production from the field by 80 percent. Net production averaged 12,400 BOPD at year-end. Development continues on the nearby Su Tu Den discovery with first production expected in 2004. The Su Tu Vang discovery is under appraisal.

Bayu-Undan Project Taking Shape

Bayu-Undan, a major natural gas and gas liquids development in the Timor Sea, is being developed in two phases. Phase I is a gas recycle project that will produce, separate, store and export liquefied petroleum gas and condensate. Phase II is a gas export project that includes the sale of liquefied natural gas (LNG) into Japan.

Net daily production from Phase I is expected to average 32,900 barrels of condensate and liquefied petroleum gas in 2004. A wellhead platform was placed on site in 2002, and a new floating storage and offloading (FSO) facility will be towed to the field in mid-2003. Product will be offloaded from the FSO to shuttle tankers for shipment to markets throughout Asia.

In March 2002, ConocoPhillips signed an agreement with two Japanese utilities for the sale of 3 million tons of LNG per year for 17 years. This sales agreement allows the company to move ahead with Phase II of the project once the remaining legal, regulatory and fiscal issues are resolved.

Elsewhere in the Timor Sea, ConocoPhillips and its co-venturers continue to evaluate commercial development options for the natural gas and associated liquids from the Greater Sunrise fields.

Africa and the Middle East

ConocoPhillips has promising growth opportunities in both Africa and the Middle East.

Natural Gas and Exploration Opportunities in Nigeria

"Nigeria has been a strong producer for the company since the 1970s," says Henry McGee, president of Middle East and Africa. "Our strategy is to commercialize more of the area's substantial gas resources using our proprietary LNG technology, as well as explore for new opportunities offshore."

A new LNG facility near the Brass River crude oil terminal could come onstream as early as 2008. Nigeria maintained its net production in 2002, averaging 38,200 BOEPD.

Discovery Made Offshore Cameroon

ConocoPhillips made a discovery offshore Cameroon in December. The Coco Marine No. 1 exploratory well reached maximum daily flow rates of 3,000 barrels of 34-degree API gravity oil and 1.8 million cubic feet of gas during a drill stem test. ConocoPhillips and its co-venturer plan to evaluate this discovery and other identified leads in the license area.

Middle East Offers Legacy Potential

ConocoPhillips has several initiatives under way to expand its position in the Middle East, including its participation in Core Ventures 1 and 3 of the Kingdom of Saudi Arabia's Natural Gas Initiative. ConocoPhillips has a 15 percent interest in Core Venture 1 and a 30 percent interest in Core Venture 3. Discussions with the Saudi government are ongoing.

E&P Results	**2002**	2001
Net income (MM)	**$1,749**	1,699
Worldwide crude oil production (MBD)	**682**	563
Worldwide natural gas production (MMCFD)	**2,047**	1,335
Finding and development costs ($/BOE)*	**$ 4.31**	3.39

**Five-year average.*

E&P earnings improved primarily due to additional volumes after the merger and slightly higher realized worldwide crude oil prices, partly offset by a drop in the average U.S. Lower 48 natural gas price.

Refining and Marketing

A Global Downstream Leader Emerges

With the completion of its merger of equals in 2002, ConocoPhillips combined two strong organizations to create one of the largest downstream businesses in the world.

The company's global refining business includes interests in 18 refineries with a crude oil refining capacity of 2.6 million barrels per day (BPD). The marketing organization includes branded outlets in the United States, Europe and Asia. A comprehensive global transportation network, including shipping and pipelines, supports the refining and marketing assets.

Jim Nokes, executive vice president of ConocoPhillips' global downstream business, believes that highly capable people are the most valuable assets realized in the merger. "The merger created a strong business for ConocoPhillips," says Nokes. "But it's our people that make the difference. They have the talent, experience and dedication required to make it successful."

Following the merger, the downstream organization has focused on integrating assets to maximize their combined capabilities. Nokes expects ConocoPhillips' downstream organization to generate $470 million in annual synergies, a 135 percent increase over the original synergy target of $200 million.

The downstream organization has a straightforward strategy for achieving first-quartile performance. Says Nokes, "We will continue our relentless pursuit of operating excellence and a low cost structure, while leveraging integration within our global organization and with ConocoPhillips' Exploration and Production segment."

The downstream organization also plans to utilize in-house research and development capabilities to capitalize on proprietary desulfurization technology, as well as its expertise in alkylation and coking. ConocoPhillips' strong technology and engineering resources will help deliver low-cost solutions as the company moves toward increasing its clean fuels production.

Jim W. Nokes, *Executive Vice President, Refining, Marketing, Supply and Transportation*

ConocoPhillips is developing regional strategies within the United States to integrate its refining base with key marketing and transportation operations. The effort is focused on creating a sustainable, cost-competitive supply of fuels to ConocoPhillips' customers and improving the company's competitive position in each region.

"These strategies will enable us to improve our return on capital employed and create strong cash flow for ConocoPhillips," adds Nokes.

Refining Gearing Up for Cleaner Fuels

In the United States, the merger brought together a network of 12 ConocoPhillips refineries with a total crude oil throughput capacity of some 2.2 million BPD, excluding refineries in Denver, Colo., and Woods Cross, Utah, that the company is divesting as part of an agreement with the U.S. Federal Trade Commission. Internationally, the merger resulted in ConocoPhillips having ownership or interest in six refineries in Europe and Malaysia.

The geographic diversity of ConocoPhillips' refineries helps set the company apart from its competitors, especially in the United States. For example, ConocoPhillips benefits from having its refineries located throughout the country, which allows the company to take advantage of market opportunities wherever they occur.

Coking units at several of the company's refineries enable ConocoPhillips to process large volumes of heavy, high-sulfur, lower-cost crude oils. This capability helps mitigate the impact of fluctuations in crude oil prices and gives ConocoPhillips an advantage over other refiners that have limited flexibility in the types of crude oils they can process.

ConocoPhillips is benefiting from recent and ongoing improvements at its refineries. Work progressed throughout 2002 on two major projects. A new fluid catalytic cracking unit expected to be fully operational in the second quarter of 2003 at the Ferndale, Wash., refinery will enable it to significantly improve gasoline production per barrel of crude oil input. A new polypropylene plant that became operational in March 2003 at the Bayway refinery in Linden, N.J., is capable of upgrading chemical feedstocks produced there into 775 million pounds per year of plastic resins used to manufacture automotive parts, textiles, films, carpets and other products.

The company is well under way with a program to meet regulatory clean fuels requirements throughout its refining system. The company plans to spend approximately

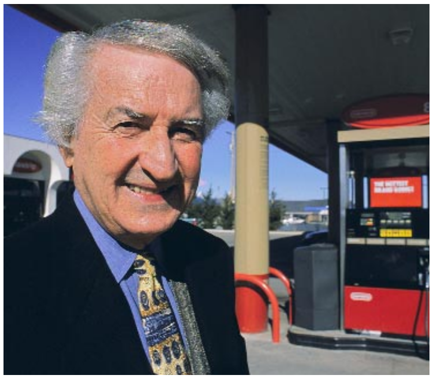
$400 million per year for the next two years on clean fuels projects in the United States and already is well ahead of regulatory mandates for clean fuels specifications in Europe.

A major expansion of the alkylation unit at the Los Angeles, Calif., refinery was completed in the first quarter of 2002, increasing its ability to produce non-MTBE (methyl tertiary-butyl ether) gasoline. Construction of a new ultra-low-sulfur diesel project is expected to begin in the second half of 2003 at the company's San Francisco, Calif., refinery complex. The project will help improve air quality while making the refinery more efficient and competitive. The project also will enable the refinery to more efficiently process crude oil from the company's operations on Alaska's North Slope. A clean fuels project that will allow the Humber refinery in the United Kingdom to produce more ultra-low-sulfur gasoline is scheduled for completion by mid-year 2003.

ConocoPhillips' clean fuels initiatives also are enhanced by the company's proprietary S Zorb™ Sulfur Removal Technology (S Zorb). A 6,000-BPD S Zorb gasoline unit at the company's Borger, Texas, refinery demonstrates the effectiveness of S Zorb to other refiners interested in licensing the technology. ConocoPhillips is building a larger S Zorb gasoline unit at its Ferndale, Wash., refinery.

Tom Nimbley, president of North America Refining, says the company intends to be the best refiner in the industry by making each of its refineries first-quartile performers.

Part of the San Francisco, Calif., refining unit, the Santa Maria facility is one of several ConocoPhillips refineries with coker units. The ability to produce petroleum coke enables ConocoPhillips to take advantage of lower-cost, heavy, high-sulfur crude oils.



ConocoPhillips' marketing efforts rely on the strength of well-known brands such as Conoco and Phillips 66, and long-term relationships with independent marketers, like Jerry Perry (right) of Grace Petroleum in Carthage, Mo. Perry has marketed fuels and lubricants under both brands for more than 50 years. "We always felt we were working with the two best companies in the business," says Perry. "With the combination of their marketer programs, we think we're working with a truly great company."

"To make our goal a reality, ConocoPhillips must be a safe, reliable and environmentally responsible operator," says Nimbley. "We will maintain a competitive edge by processing lower-cost crude oils and by utilizing our integrated network and commercial expertise to maximize our return on assets."

Marketing Builds Strength Through Wholesale Network

The merger created a global marketing network of 17,000 branded outlets, including almost 14,000 in the United States and some 3,000 in Europe and Asia, excluding those sites recently announced for divestiture.

In the United States, the company's marketing assets, like its refining assets, are located in each major region, with outlets in 48 states. An extensive network of marketers and dealers operates more than 95 percent of these outlets.

ConocoPhillips primarily markets gasoline under three U.S. brands: Conoco, Phillips 66 and 76. Conoco and Phillips 66 are strong brands in the Midcontinent, the Rockies and parts of the Southeast, while the 76 brand is popular on the West Coast.

Internationally, the company applies a strategic niche marketing approach to outperform the competition. In Europe, the company's low-cost, high-volume network of some 2,900 outlets, primarily Jet branded, is supplied mainly by ConocoPhillips' Humber refinery in the United Kingdom and the MiRO refinery in Karlsruhe, Germany — historically two of the most efficient refineries in Europe. ConocoPhillips markets under the Jet brand at 137 retail outlets in Thailand, where the company has captured 6 percent of the retail market. The company also is developing a network of outlets under the ProJET brand in Malaysia.

Marketing is delivering synergies through consolidating staffs and administrative offices, implementing best practices, and finding more effective ways to utilize advertising, promotion and support programs. The company has made a strategic decision to focus its marketing efforts on wholesale and commercial customers. As part of an overall disposition program directed at reducing downstream assets by $1.5 billion to $2 billion over the next 18 months, ConocoPhillips plans to sell a large number of its retail stores.

Building on a long tradition, ConocoPhillips will continue to strengthen its relationships with independent marketers and provide ways to help improve their profitability and financial strength. Because the company's portfolio includes strong regional brands, it makes strategic sense to move much of the company's fuels products through the wholesale channel.

According to Mark Harper, president of Wholesale Marketing for North America, ConocoPhillips intends to be an extremely reliable, low-cost supplier of quality products and efficient, value-adding systems to support its historic brands.

"We can't be successful unless our marketers and dealers also are financially sound," Harper says. "We are committed to becoming an even more customer-focused, value-adding supplier for our marketers and dealers."

One example of the company's commitment to helping its marketers and dealers improve their profitability is a proprietary extranet Web site that provides quick, easy access to electronic forms, policies and guidelines related to each brand. This business-to-business sharing of electronic information streamlines communication, saving time and money.

Specialty Products Diversify Downstream Portfolio

ConocoPhillips manufactures and globally markets a number of high-value specialty products. These products include finished lubricants, specialty petroleum coke, proprietary pipeline flow improvers and solvents.

The company markets lubricants under the Conoco, Hydroclear, Phillips 66, 76 and Kendall brands in the United States and in more than 40 other countries. The combination of the lubricant businesses has resulted in ConocoPhillips becoming the fourth-largest U.S. lubricant supplier. The company markets through a network of petroleum marketers, and directly to original equipment manufacturers, large end-users, retailers and installers.

ConocoPhillips is a co-venturer in Penreco, a worldwide specialty products company manufacturing specialty oils for a variety of industries, including food, pharmaceuticals, cosmetics and household products. Penreco also markets specialty solvents and process oils.

Additionally, ConocoPhillips is a co-venturer in the Excel Paralubes base oil facility located in Lake Charles, La. This world-class facility produces almost 330 million gallons per year of high-quality base oils used in making lubricants.

With production sites in North America and Europe, ConocoPhillips is a major producer of high-value, premium grade petroleum coke, used in the steel and aluminum industries. "Our coke production capability provides significant economies of scale and logistical advantages relative to our competitors," says Carin Knickel, president of Specialty Businesses. "Production facilities that are integrated with the company's refineries — coupled with our proprietary technology — provide low operating costs and high-quality products to global customers."

Transportation Focused on Lower Costs

In the United States, ConocoPhillips' refining and marketing assets are linked through a transportation network of some 31,500 miles of crude oil, raw natural gas liquids and refined products pipelines, 82 terminals and a complement of truck and rail facilities. The company also operates a domestic barge and international marine business and maintains an unwavering commitment to safe, environmentally responsible operations.

In support of its U.S. refining operations, ConocoPhillips charters a fleet of 15 double-hulled crude oil tankers, with capacities ranging from 650,000 to 1.1 million barrels. In addition, the company has agreements for the long-term chartering of five double-hulled crude oil tankers that are currently under construction to replace older vessels that supply its U.S. East Coast refinery operations. Delivery is expected in the second half of 2003.

These combined transportation assets provide strategic opportunities to reduce refinery crude oil costs and improve regional integration between ConocoPhillips' refineries and its marketing network. The company's transportation infrastructure gives it the flexibility to provide cost-effective supply alternatives in response to changing market conditions.

"Our primary focus always is on providing safe, reliable, cost-effective and environmentally responsible transportation solutions for ConocoPhillips," says Steve Barham, president of Transportation.

R&M Results	**2002**	2001
Net income (MM)	**$ 143**	397
Worldwide crude oil throughput (MBD)	**1,813**	706
U.S. petroleum products sales (MBD)*	**2,096**	933
International petroleum products sales (MBD)*	**162**	10

**Excludes spot market sales.*

R&M earnings declined as the addition of the Conoco assets was more than offset by lower refining margins along with asset impairments.

The company's Humber refinery in the United Kingdom is one of the most advanced in Europe. Since it was built in 1969, approximately $750 million has been invested to enhance efficiency, safety and environmental protection. Additions in recent years include a vacuum distillation unit to process high-acid crude oil from the latest generation of North Sea fields; a wastewater plant to clean up discharges from the refinery; and a clean fuels plant producing ultra-low sulfur fuels years ahead of European legislation.

Midstream

Working to Get More From Midstream Assets

ConocoPhillips' Midstream assets include the company's 30.3 percent interest in Duke Energy Field Services, LLC (DEFS), one of the largest natural gas and gas liquids gathering, processing and marketing companies in the United States, as well as other midstream assets held by ConocoPhillips. Midstream gathers natural gas, processes it to extract natural gas liquids, and markets the remaining residue gas to electrical utilities, industrial users and gas marketing companies.

In 2002, DEFS had throughput of 7.4 billion cubic feet per day (BCFD) of raw natural gas and extracted 392,000 barrels per day (BPD) of natural gas liquids (NGL). ConocoPhillips' share of raw gas throughput was 2.2 BCFD, while its portion of NGL extracted was 119,000 BPD.

DEFS is focused on optimizing its large, strategically located asset base in the face of weak economic conditions throughout the midstream energy business.

"With market conditions extremely challenging, including average NGL prices about 15 percent below the previous year, DEFS is working to make the most of its existing assets," explains Jim Mogg, chairman, president and chief executive officer of DEFS. Optimization efforts in 2002 included reducing capacity restraints at some plants, upgrading compressor stations and generally improving the efficiency of gathering systems.

Says Mogg, "Our gathering and processing systems, which grew rapidly through acquisitions and expansions from 1999 to 2001, have propelled DEFS to become a major player in virtually every area where we operate with the exception of Canada, where we plan to grow. Our focus is from Alberta, Canada, to Mobile Bay, Alabama."

DEFS significantly increased its presence in the eastern Gulf of Mexico in 2002 with the acquisition of a one-third interest in Discovery Producer Services. Discovery serves both shallow and deepwater producers with gathering lines, processing facilities and a large interstate pipeline extending from near New Orleans, La., to the outer continental shelf. Discovery also operates a fixed-leg platform and gathering lines to serve productive deepwater Gulf of Mexico areas including Green Canyon, Mississippi Canyon, Ewing Bank and Atwater Valley.

As part of its program to optimize and rationalize assets, DEFS exchanged selected gathering and processing interests with a Williams subsidiary. In exchange for its interest in a processing plant and related gathering system near Wamsutter, Wyo., DEFS obtained a gathering system and three gas processing plants located in areas of Oklahoma and Texas where DEFS already has a strong presence.

The growth of DEFS is aided by its position as general partner of TEPPCO Partners, L.P., a master limited partnership. The partnership is involved in petroleum transportation, storage and marketing, petrochemical and natural gas liquids transportation and in natural gas gathering. In addition to receiving TEPPCO distributions, which rose significantly in 2002, DEFS is paid to operate and commercially manage TEPPCO's gas gathering systems.

During the year, TEPPCO acquired the 800-mile Chaparral NGL pipeline, which extends from West Texas and New Mexico to Mont Belvieu, Texas, and the 170-mile Quanah system, a West Texas NGL gathering system. The partnership also purchased the Val Verde system in New Mexico, which gathers and treats coal seam gas from the prolific San Juan Basin. In addition, TEPPCO undertook a major capacity expansion of its Jonah system, which collects gas from the Green River Basin of southwestern Wyoming.

Outside of its interest in DEFS, ConocoPhillips owns and operates other assets in the Midstream business. These assets include gas-gathering systems, processing plants, fractionators and storage facilities in the United States, Canada, Trinidad and the Middle East.

Ten owned and operated gas processing plants in the United States and Canada have a combined net inlet

Midstream Results*	**2002**	2001
Net income (MM)	**$ 55**	120
Natural gas liquids average sales price ($/BBL)		
Consolidated	**$19.07**	—
Equity	**$15.92**	18.77
Net natural gas liquids extracted (MBD)	**156**	120

**The Midstream segment includes ConocoPhillips' 30.3 percent interest in Duke Energy Field Services, LLC. It also includes company-owned natural gas gathering and processing operations, and natural gas liquids fractionation and marketing businesses, following the merger on Aug. 30, 2002.*

The addition of the Conoco midstream operations was more than offset by a decline in DEFS' net income as a result of a drop in DEFS' natural gas liquids prices and higher operating expenses.

With a throughput capacity of 2.4 billion cubic feet per day, ConocoPhillips' Empress plant in Alberta, Canada, is one of the largest natural gas processing facilities in North America. The plant's ability to separate individual natural gas liquids gives the company a strong position in the regional propane market.

capacity of 2.97 BCFD of raw natural gas. Most of the processed liquids are fractionated into components such as ethane, butane and propane to be marketed as chemical feedstock, fuel or blend stock. The company has interests in seven fractionation facilities in the United States and Canada, with a net capacity of 249,000 BPD. Natural gas and NGL storage caverns are located in Louisiana, Texas and Canada. ConocoPhillips also owns a small equity interest in two additional processing plants in the United States, as well as midstream assets in Trinidad through a 39 percent equity interest in Phoenix Park Gas Processors Limited.

In the Middle East region, the Des Gas plant in Syria is complete, and ConocoPhillips is under contract to operate the facility.

Chevron Phillips Chemical Company Improves Results

ConocoPhillips' joint-venture chemical company, Chevron Phillips Chemical Company LLC (CPChem), is successfully pursuing its goals of improving results and becoming the safety pacesetter in the chemicals industry.

CPChem President and Chief Executive Officer Jim Gallogly attributes the company's improved results to a focus on operational excellence, cost reduction, capital stewardship, profitable growth and an organizational commitment to continuous improvement.

Outstanding Safety Performance Aids in Operational Excellence

CPChem is continuing its efforts to lead the chemicals industry in safe and reliable operations. It posted a 30 percent improvement in its 2002 safety record and dramatically improved plant reliability. Based on the Occupational Safety and Health Administration recordable incident rate, as benchmarked by the American Chemistry Council, CPChem is now among the industry's elite in safety. Approximately one-third of CPChem's manufacturing facilities had no employee recordable injuries during the year. "Every employee has demonstrated a personal commitment to safety," says Gallogly. "When safety improves, reliability also improves."

Synergy Savings and Cost Reductions Continue

Since its creation in mid-2000, CPChem has continued to realize significant savings. Cost reductions and capital discipline are an ongoing focus of CPChem. The sustained effort has captured in excess of $200 million of net recurring annual synergies and cost savings, surpassing the target of $150 million originally estimated when CPChem was formed. "We have taken nothing for granted in addressing our cost competitiveness," says Gallogly. "Our employees have enthusiastically embraced this emphasis."

Chemicals Results*	**2002**	2001
Net loss (MM)	**$ (14)**	(128)
Major product production		
Ethylene (MMlbs)	**3,217**	3,291
Polyethylene (MMlbs)	**2,004**	1,956

**The Chemicals segment consists of ConocoPhillips' 50 percent interest in Chevron Phillips Chemical Company LLC.*

Though Chemicals' earnings improved somewhat from 2001, the worldwide chemicals business remains depressed due to weak economic conditions resulting in a net loss for CPChem.

Foundation For Growth

Laying a solid foundation for growth is key to CPChem's global strategy. Internationally, CPChem's global reach has been significantly extended by the recent dedication of a world-scale petrochemical complex in Mesaieed Industrial City, Qatar. The facility is designed to produce 1.1 billion pounds of ethylene, 1 billion pounds of polyethylene and 100 million pounds of 1-hexene annually. The facility will be operated by Qatar Chemical Company Ltd. (Q-Chem), a joint venture of Qatar Petroleum (51 percent) and CPChem (49 percent).

A second project, called Q-Chem II, will involve two additional joint ventures in the State of Qatar. The first venture, in which Qatar Petroleum holds a 51 percent interest and CPChem has a 49 percent interest, includes the construction of two ethylene derivative units adjacent to the existing Q-Chem complex in Mesaieed Industrial City. These polyethylene and normal alpha olefins facilities will utilize proprietary CPChem technology. The second joint venture, owned by Q-Chem II and Qatofin (a joint venture of Atofina SA and Qapco) will involve the construction of an ethane cracker to be located in Ras Laffan Industrial City. The cracker will provide ethylene feedstock to the derivative units. Final approval of the project is anticipated in 2004, with startup expected in 2007. Together, the Qatar projects typify CPChem's strategy to secure advantaged feedstocks and achieve greater global diversity.

CPChem has other expansion projects under way. The Jubail Chevron Phillips (JCP) project is a joint venture with the Saudi Industrial Investment Group to produce styrene and propylene. JCP will be owned 50 percent by CPChem and will be located adjacent to the existing Saudi Chevron Phillips (SCP) Aromax® facility in Al Jubail, Saudi Arabia. Plans call for the SCP plant to provide benzene feedstock to the closely integrated JCP facility. Final approval of the project is anticipated in late 2003, with startup expected in 2006.

CPChem is realizing significant results in its domestic business as well. A modernization project of CPChem's styrene production facilities in St. James, La., was completed in 2002. This plant expansion increased capacity by approximately 25 percent and further enhanced its cost position.

In a 50/50 partnership with BP Solvay, CPChem is commissioning a 700 million-pound-per-year high-density polyethylene plant at its Cedar Bayou facility in Baytown, Texas. The new facility will use CPChem's proprietary loop slurry technology, and both companies will equally share the capacity. It will be the largest single-loop production system ever built.

In October 2002, CPChem announced plans to build a new cyclohexane production facility at its Port Arthur, Texas, plant. This project has received final approval and will increase the cyclohexane capacity of the facility by 587 million pounds per year. Construction is slated to begin in early 2003 with completion and startup scheduled for early 2004.

"Going forward, these and other capacity expansions, combined with continued attention to safety, reliability and costs, position CPChem well for the future," adds Gallogly.

CPChem employees Becky Rickett and Jesse Perez review natural gas liquids status reports at CPChem's Sweeny facility in Old Ocean, Texas. The Sweeny facility manufactures 4.1 million pounds of ethylene and 1.1 million pounds of propylene per year, used to make polymers and other products from which many common consumer goods are manufactured.

Emerging Businesses

Technologies Position ConocoPhillips for the Future

ConocoPhillips' emerging businesses — including fuels technology, gas-to-liquids, power generation and emerging technologies — are closely aligned with the company's core businesses and provide future potential growth opportunities.

Another emerging business, carbon fibers, was shut down in early 2003 after a careful review of a number of different continuation options and as the result of the cumulative effect of market, operating and technology uncertainties.

According to John Lowe, executive vice president of Planning and Strategic Transactions, Emerging Businesses has two primary areas of focus: monitoring all the technological advances taking place in the industry and finding low-cost options related to strategic technology that can competitively position the company over the next 10 to 20 years.

"We have a disciplined and consistent process for prioritizing the funds we dedicate to emerging businesses," explains Lowe. "The opportunities must be significant, we must have a core competency in the area and we must feel that we can create a competitive advantage. We must prove the technologies work before we assume they can produce returns. We won't invest large amounts of money into any technologies until they are proven and will provide returns that can compete with upstream and downstream projects."

S Zorb Units Will Produce Cleaner Fuels

ConocoPhillips is continuing to license its S Zorb™ Sulfur Removal Technology to refiners. The company also is generating additional value by applying the innovative process within its own North America refining system.

John E. Lowe, *Executive Vice President, Planning and Strategic Transactions*

"S Zorb is an effective technology for reducing the amount of sulfur in transportation fuels," says Brian Evans, manager of fuels technology. "Potential customers include any refiner that must meet impending government requirements for lower levels of the pollutant in their gasoline and diesel fuels."

In 2002, several refiners in North America began engineering work on S Zorb gasoline units. First production from a non-ConocoPhillips S Zorb gasoline unit is expected in 2004. Also, ConocoPhillips signed its first two combined gasoline and diesel licenses with major refiners in Asia and North America.

The company's first S Zorb diesel unit is in the planning stages at the Billings, Mont., refinery, and construction is under way on an S Zorb gasoline unit at ConocoPhillips' Ferndale, Wash., refinery. S Zorb gasoline units are being studied for the Sweeny, Texas, and Lake Charles, La., refineries.

S Zorb has received accolades for its environmental benefits, including the Texas Natural Resources Conservation Commission's Environmental Excellence Award for Innovative Technology and *Business Week's* Global Energy Award for Most Innovative Commercial Technology.

New Plant Demonstrates Gas-to-Liquids Technology

Commissioning of the company's new gas-to-liquids (GTL) demonstration plant in Ponca City, Okla., will begin in 2003. The GTL process produces clean liquid fuels from natural gas. Once the technology is proven, ConocoPhillips will be capable of constructing full-scale GTL facilities.

"The successful operation of our new demonstration plant using ConocoPhillips' proprietary technology will take the company to the next level by providing valuable engineering and design data for a commercial-scale plant," says Jim Rockwell, manager of GTL.

In addition to providing data to be used in designing a commercial-scale plant, the new demonstration plant will allow potential joint-venture partners — primarily owners of stranded gas reserves around the world — to fully evaluate ConocoPhillips' GTL technology. That technology includes a unique synthesis gas process — the first step in converting natural gas to a liquid — that has been recognized as being more efficient and producing fewer emissions than other processes currently available.

ConocoPhillips uses small-scale plants to evaluate and demonstrate the capabilities of its technologies. The 6,000 barrel-per-day S Zorb gasoline plant (left) at the Borger, Texas, refinery helps the company license S Zorb Sulfur Removal Technology to other refiners. A gas-to-liquids plant (above) expected to start up this year at the Ponca City, Okla., refinery will provide important data for building future commercial-scale plants.

Power Projects Lower Costs and Leverage Gas Assets

"ConocoPhillips looks for opportunities to reduce costs, improve reliability and increase integration," says Mike Swenson, manager of power, midstream gas and water. "We can do this by integrating power projects with upstream developments and through the development of combined heat and power — or cogeneration — facilities in conjunction with company sites, like the project under way at the Humber refinery in the United Kingdom."

A 730-megawatt cogeneration plant will supply steam and electricity to the company's Humber refinery. Excess steam will go to a neighboring refinery and excess electricity will be fed into the country's national grid. The plant also will have the design capacity to provide power and heat to other companies in the area. The plant is scheduled to come onstream in 2004.

Pioneering the Future of Energy

The role of emerging technologies is to develop strategic new business opportunities that will provide growth options for ConocoPhillips well into the future. The emerging technologies portfolio includes a variety of business ventures and technical programs that are pioneering the future energy landscape, including renewable energy, advanced refining processes, energy conversion technologies and hydrocarbon upgrading opportunities.

Ann Oglesby, manager of emerging technologies, explains, "We start by identifying focus areas that include markets, products or technologies that may be opportunity areas for ConocoPhillips. Within a focus area, we assess the commercial and technical issues that must be addressed to lead to a successful business."

Emerging technologies follows a structured process for screening opportunities and progressing those with the most potential along a phased development program. Some programs are based on internal research and development, while others are developed jointly with third parties including small and large companies, universities, government and industry organizations. In all cases, emphasis is placed on ensuring a sufficient strategic business case to warrant development.

Emerging Businesses Results	**2002**	2001
Net loss (MM)	**$ (310)**	(12)

Emerging Businesses experienced increased costs from the addition of Conoco's gas-to-liquids, carbon fibers and power generation activities. In connection with these activities, the loss in 2002 includes a $246 million write-off of acquired in-process research and development costs related to Conoco's natural gas-to-liquids and other technologies. See page 44 in Management's Discussion and Analysis for further information.

Commercial

Gaining the Most Value from Supply and Demand

The Commercial organization was created to bring together all of the company's commodity supply chains into a global commercial business. Commercial generates value by optimizing the commodity flows of the upstream and downstream businesses, including nearly 2.5 billion barrels of crude oil and products and more than 2 trillion cubic feet of natural gas annually across the globe.

The group includes 550 people who market ConocoPhillips' equity crude oil and natural gas production, market third-party natural gas, select and procure crude oil, and distribute products for the company's 18 refineries. Commercial also supplies the gas and power needs of company assets and markets the gas, liquids and power produced at company facilities.

"Our large, diverse asset base gives ConocoPhillips a competitive advantage," says Philip Frederickson, executive vice president of Commercial. "Having a single, integrated organization that sees both the supply and demand perspectives enables us to globally optimize across the whole hydrocarbon value chain."

The Commercial group includes commodity buyers, traders and marketers who execute thousands of transactions a day. Offices in Houston, London, Singapore and Calgary provide around-the-clock trading capabilities. For maximum effectiveness, employees work on common trading floors at each location along with professionals who handle risk management, planning, scheduling, transportation, accounting and other support functions.

The crude oil, refined products, natural gas, gas liquids and power markets can be extremely volatile and are influenced by many factors, including world political and economic events, weather patterns, and numerous other issues impacting supply and demand that are in constant flux. "Having all these experts together facilitates constant, instantaneous communication needed to make rapid decisions, which is critical in this arena," comments Frederickson.

Philip L. Frederickson, *Executive Vice President, Commercial*

Pam Johnson, director, supply-power marketing, keeps a close watch on commodity prices at the company's trading floor in Houston, Texas. Instantaneous communications allow traders like Johnson to minimize ConocoPhillips' costs for purchasing electric power, natural gas, crude oil and refined products, as well as enabling the company to realize the best prices when selling these commodities.

An important function within the Commercial organization is managing the risks inherent in the business. The risk management group uses highly disciplined processes to identify and measure the potential for financial loss due to credit exposure and price volatility in the market. The Commercial group's risk is controlled within prescribed volume and loss limits. "The goal of risk management is to ensure that the trading groups understand the risks they are incurring," explains Frederickson. "Therefore, they know if they are getting appropriate returns on those risks."

Evidence of the benefits of the global Commercial structure is found in the significant number of synergy opportunities already being captured by the group:

- Regional commodity supply and demand imbalances are significantly reduced;
- New, more cost-effective transportation and distribution options are being utilized;
- More crude oil supply substitution and marketing options are being leveraged;
- Expanded regional natural gas supply availability is being marketed to customers; and
- Significant new options for responding to supply disruptions are being utilized, most recently during the national labor strike in Venezuela.

Financial Strategy

Emphasis on Discipline

ConocoPhillips' financial strategy emphasizes discipline — on costs, capital spending and the balance sheet — in an effort to reduce debt and improve returns to shareholders.

"The overriding emphasis throughout the company is to improve our return on capital employed (ROCE) to be competitive with the largest companies in the industry," says John Carrig, executive vice president of Finance and chief financial officer. "We've already begun implementing the steps necessary to meet this objective, like announcing a lower, more disciplined capital budget for 2003 and an asset disposal program designed to high-grade the asset base. This includes divesting a substantial number of retail marketing outlets and higher-cost, shorter-lived Exploration and Production (E&P) properties."

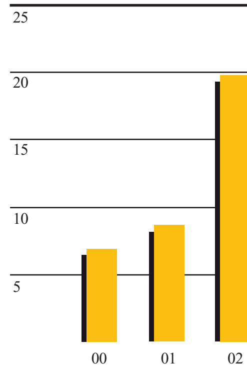
ConocoPhillips' capital budget of $6.6 billion is $2 billion less than the combined capital budgets of the two merged companies. Seventy-five percent of the company's 2003 capital budget is dedicated to E&P, which has historically provided higher returns than other businesses. "Our capital program is value-oriented," says Carrig. "We want attractive returns for every dollar spent."

The company plans to increase its midcycle ROCE over the next several years from the current levels to better compete with the best-performing companies in the sector. The company expects to achieve a higher ROCE through capital discipline, synergy capture and sales of low-returning assets.

At the end of 2002, the company's total debt was $19.8 billion. In 2003, the company plans to apply a portion of operating cash flow and cash flow from asset sales toward reducing the debt. This should bring the debt down to approximately $18 billion to $19 billion by year-end 2003. In 2004, the company expects another $1 billion of debt reduction from capturing a full year of cost synergies, improved cash flow and additional asset sales.

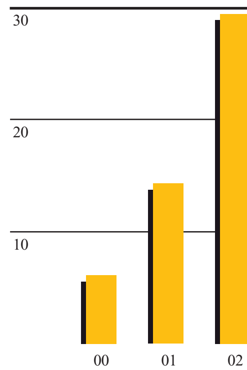
John A. Carrig, *Executive Vice President, Finance, and Chief Financial Officer*

Total Debt (Billions of Dollars)



ConocoPhillips' total debt at the end of 2002 was $19.8 billion. The company assumed $12 billion in connection with the merger. The company plans to reduce its existing debt by approximately $2 billion over the next two years by utilizing a portion of operating cash flow and cash flow from asset sales.

Common Stockholders' Equity (Billions of Dollars)



ConocoPhillips' common stockholders' equity was $29.5 billion, and its total debt as a percent of capital was 39 percent at year-end 2002. The company plans to lower its existing debt-to-capital ratio to the mid-30 percent range over the next several years through a combination of debt reduction and earnings growth.

"Reducing debt should result in a much stronger share price, while providing more flexibility to weather a downturn in crude oil and natural gas prices," explains Carrig. "Less debt also allows for consistent capital funding and the flexibility to take advantage of new opportunities."

With lower debt, ConocoPhillips' credit rating should improve. "Stronger ratings will give us more financial flexibility and attract a wider base of shareholders," says Carrig.

In addition to ConocoPhillips' commitment to reduce debt and control costs, the company also is committed to providing benefits for employees and retirees. The company will invest approximately $350 million annually over the next five years in its U.S. pension and employee benefit funds, ensuring strong support of these programs.

Says Carrig, "Our outlook is good. We have excellent management and strong oversight from proven control systems in place. We need to maintain our focus on discipline with regard to costs, capital spending and the balance sheet. We have a solid plan to improve returns, and we have the experience and the will to make it work."

corporate review

Fishing is a common activity at this pond located on the property of ConocoPhillips' Wood River, Ill., refinery. Wherever ConocoPhillips operates, the company and its employees strive to protect the environment and be a positive influence in the community.

Environmental stewardship is just one of the functions promoted and supported by ConocoPhillips' corporate staffs. The staffs provide a variety of services and functions, including data management, community leadership, employee compensation and benefit programs administration, and helping to ensure that company facilities adhere to strict safety and environmental standards.

Global Systems and Services

Improving Efficiency Across Business Units

Five complementary segments of related services make up Global Systems and Services (GSS), led by Gene Batchelder, senior vice president of Services and chief information officer. Included are aviation, facilities management, financial services, information services and procurement.

While groups within GSS might appear unrelated, Batchelder says collaboration and shared support lead to improved value and increased cost efficiency. "One of our primary goals is to help our businesses capture opportunities beyond previous expectations. Two of the most important paths to success are through improved relationships and better information sharing.

"GSS delivers reliable, accurate and cost-effective support to ConocoPhillips businesses around the world," says Batchelder. "Two key, long-term goals are to streamline processes and bundle services to take advantage of efficiencies and common systems that will help the company achieve better synergies than would have been possible by the individual businesses."

The more than 5,000 employees and contractors worldwide who make up GSS are committed to consistently delivering best-in-class services to employees anywhere, anytime. Integration of the groups within GSS in the upcoming months will be aimed at even further improving efficiency, value and cost savings.

GSS touches virtually every level of the company. Global aviation services reduces travel time and expenses with more than 1,000 round trips annually, including a shuttle that flies between Ponca City and Bartlesville, Okla., and Houston, Texas.

Global facilities management includes office space management in six primary cities, including wellness centers, cafeterias and global office lease oversight. In addition, the group has responsibility for employee travel and vehicle fleet management.

E.L. Batchelder, *Senior Vice President, Services, and Chief Information Officer*

Sonja Meredith, global financial services, and Rocco Iannapollo, global information services, are part of the Global Systems and Services (GSS) organization based in Bartlesville, Okla. The GSS group provides an array of services that help other ConocoPhillips business groups do their jobs effectively and efficiently.

Global financial services provides financial and real property expertise to domestic operations, with a goal of leveraging services globally as shared services opportunities are identified and developed across the company. Functions in this area include accounts payable, treasury services, excise tax, general accounting, real property administration and upstream and downstream financial services.

Global information services encompasses all the company's systems applications and infrastructure, and telecommunications support. The responsibility to provide reliable, accurate products and services related to information systems is underscored by the company's increasing dependence on computer hardware and software.

Global procurement services manages and integrates contracts for supplies and services throughout the company and leads the development of procurement best practices. Procurement services range from paper for copiers, to catalyst for cat crackers, to maintenance services, to pipe, valves and fittings.

"The employees in GSS understand that reliable, accurate systems, services and materials are required to enable employees around the world to perform at peak levels," says Batchelder. "We are determined to deliver world-class services and products to ConocoPhillips regardless of location or the magnitude of the request. Our vision is to become the benchmark services function in the industry."

Health, Safety and Environment

Safety Is Always Our First Priority

The emergency response team at the Alliance refinery near New Orleans, La., practices firefighting skills. Regular training is an important part of the safety programs at all of ConocoPhillips' operating facilities. The Alliance refinery completed its safest year ever in 2002, achieving zero recordable incidents.

ConocoPhillips continued to maintain a strong environmental and safety performance in 2002 despite the tremendous amount of merger activity.

"Our first priority always has been and will continue to be safety," says Bob Ridge, vice president of Health, Safety and Environment (HSE). "We have devoted a significant amount of time and energy to build a world-class HSE organization."

ConocoPhillips seeks to earn the public's trust and to be recognized as the leader in health, safety and environmental performance. The company's HSE policy states in part:

"ConocoPhillips is committed to protecting the health and safety of everybody who plays a part in our operations, lives in the communities where we operate or uses our products. Wherever we operate, we will conduct our business with respect and care for both the local and global environment and systematically manage risks to drive sustainable business growth."

HSE standards help fulfill this commitment by describing mandatory, issue-specific company health, safety or environmental requirements. These standards are put in place through a management system that provides a consistent framework for managing HSE issues to protect people, assets and the environment. Each business unit implements an HSE management system tailored to their specific needs and that includes a process-based approach for continuously improving performance.

In addition, ConocoPhillips has an incident management plan designed to effectively respond to and manage any emergency incident. Operations have well-developed emergency preparedness and response plans suited for their specific risk profile. These plans anticipate potential scenarios and minimize the negative impacts of unforeseen accidents or natural disasters. Well-trained response teams carry out these plans.

Robert A. Ridge, *Vice President, Health, Safety and Environment*

ConocoPhillips is building on a rich tradition of excellence in safety and environmental stewardship. Highlights from 2002 include:

- Since completion of the merger, ConocoPhillips' total recordable rate (TRR) of incidents improved 18 percent compared to the combined TRR of Phillips and Conoco during the first eight months of 2002; and contractor safety improved 13 percent in 2002 compared with 2001.
- ConocoPhillips Exploration and Production operations in China and the company's Hartford, Ill., lubricants plant were certified under the internationally recognized ISO 14001 environmental management system. Other ConocoPhillips operations already certified ISO 14001 include the Humber refinery in the United Kingdom and the Gulf Coast lubes plant in Sulphur, La.
- The Borger, Texas, refinery and natural gas liquids center was awarded STAR recognition, the highest level of performance under the U.S. Occupational Safety and Health Administration's Voluntary Protection Program.
- The Alpine development on Alaska's North Slope received an award for excellence in waste reduction and environmental responsibility from the non-profit organization Green Star. Alpine employees voluntarily implemented a thorough waste reduction and pollution prevention plan.

People and Ethics

Developing Employees for Business Success

One of ConocoPhillips' key goals is attracting and retaining top talent — individuals with the knowledge and skills to implement the company's business strategy and who support our values.

According to Joseph High, vice president of Human Resources, the opportunities most prized by employees are:

- Working for a winning organization;
- Working with great leadership; and
- Working in a job is challenging.

"At ConocoPhillips, we provide all three," says High. "We take our commitment to providing our employees with challenging opportunities in a healthy environment as seriously as any business goal. It's our way of attracting and retaining talented individuals who demonstrate the capability to help us build a strong company and create lasting value for our shareholders."

Company recruiter LeAnn Luedeker (left) discusses career opportunities at ConocoPhillips with University of Oklahoma students Nicholas Walls and Jessica Miller. Seeking the best and brightest individuals from a variety of backgrounds is at the center of ConocoPhillips' hiring efforts.

Recruiting, Retaining and Rewarding Top Performers

Maximum effort has gone into ensuring that ConocoPhillips employs individuals with the skills and values needed to implement its business strategy. Throughout the merger transition, a team of employees integrated business units and functions, matching core talents and positions.

"Maximizing performance is a continuous process," notes High. "Our new Performance Management Process aligns and measures individual performance expectations to achieve targeted business results. It's a performance agreement designed to help managers encourage the development of their employees, while helping employees answer the question: 'What can I do to make a significant contribution to the company's success?'"

Another way the company maximizes performance is by rewarding and recognizing top performers. Employees earn bonuses based on the company's overall performance and employees' individual contributions. The company also recognizes outstanding individual and team employee achievements with the annual SPIRIT of Performance awards.

Joseph C. High, *(left)*
Vice President, Human Resources

Rick A. Harrington, *(right)*
Senior Vice President, Legal, and General Counsel

Redesigning Compensation and Benefits

Consolidating operations and employment included consolidating all of the company's pay and benefit programs. As of January 1, most of the company's separate benefit programs, including payroll, had been rolled into one program. Human Resources also has created one set of policy guidelines and procedures.

"At every stage, an effort was made to incorporate competitive features consistent with our business needs," says High. "Just as we wanted the best person in every job, we designed a total compensation and benefits package that meets diverse employee needs and compares favorably with those of other large, integrated companies."

Renewing Our Commitment to Corporate Ethics

"At ConocoPhillips, integrity is a core value, and we take it very seriously," says Rick Harrington, senior vice president of Legal and general counsel. "It's a condition of employment; everyone in the company is accountable."

The company has established a compliance and ethics committee to:

- Establish and publish compliance and ethics policies;
- Design and implement training programs; and
- Periodically review and assess corporate performance in key compliance areas, including: antitrust, commodity trading, insider trading and financial reporting.

Social Investment

Elevating Our Position in the Global Community

More than just charitable, feel-good activities, social investment encompasses philanthropy and community outreach, and is important to ConocoPhillips' approach for delivering superior financial results.

"Social investment positions ConocoPhillips positively with our customers, stakeholders and with government leaders," says Tom Knudson, senior vice president of Government Affairs and Communications. "When we address local needs and environmental problems, host governments more readily view us as partners in their communities — creating favorable settings for our businesses to flourish."

Reaching Outward

Community outreach activities harness employees' sense of pride and desire to work for a good corporate citizen. In Houston, Texas, the Keep 5 Alive program mobilizes hundreds of employee and family volunteers to paint and repair homes of elderly and disabled homeowners in the inner city. In Alaska, employees contribute time and resources to the Red Cross Masters of Disaster program, teaching children how to survive natural disasters. ConocoPhillips continues to have a significant community presence in Oklahoma, where employee and company support of education, the arts and other charities in Bartlesville, Ponca City and throughout the state remain at pre-merger levels. Around the world, ConocoPhillips funds educational initiatives and community enrichment activities.

Taking Environmental Stewardship Seriously

The company works hard to be the neighbor of choice. In Alaska and Russia, ConocoPhillips uses ice roads to protect fragile tundra. The company's environmental protection initiatives in Russia have been recognized with two annual Lomonosov Awards.

Thomas C. Knudson, *Senior Vice President, Government Affairs and Communications*

Mandy Tulloch, development coordinator for the Conoco Natural History Centre at the University of Aberdeen in Scotland, shows off a large common house spider brought in for identification by a worried resident. ConocoPhillips provides financial support to the center that was established to promote environmental education in the community and at local schools.

For more than 60 years, ConocoPhillips has carried out oil and gas exploration and development in the environmentally sensitive home of the endangered Aransas-Wood Buffalo Whooping Crane at the Aransas National Wildlife Refuge in Texas. Limiting drilling activity to months when the flock summers in Canada, the company has proudly watched the flock increase from fewer than 20 birds to more than 180 birds.

Through its support of the International Crane Foundation, the company has enabled migration studies of waterfowl and their natural habitats along Bohai Bay's coastal wetlands in northeastern China.

Meeting Present Needs Without Compromising the Future

Facilitating development in Venezuela's Gulf of Paria, ConocoPhillips funds workshops on health and water purification for the local community and sponsors literacy and bilingual programs for the indigenous Warao. In Alberta, Canada, ConocoPhillips decreased forest fire potential, eliminated safety hazards and saved some $170,000 by using narrow clearing techniques to make a path through dense forest to lay seismic survey lines.

"Through our global operations, ConocoPhillips works to maximize financial performance while providing shareholders with an attractive return on investment," says Knudson. "Success means combining economic performance, environmental stewardship and social investment as interdependent parts of a single business approach."

Management's Discussion and Analysis 37

Selected Financial Data .61

Selected Quarterly Financial Data 61

Quarterly Common Stock Prices and
Cash Dividends Per Share 61

Reports of Management and
Independent Auditors 62

Consolidated Financial Statements 63

Notes to Consolidated Financial Statements 67

Oil and Gas Operations 95

5-Year Financial Review 104

5-Year Operating Review 105

financial review

Management's Discussion and Analysis is the company's analysis of its financial performance and of significant trends that may affect future performance. It should be read in conjunction with the financial statements and notes, and supplemental oil and gas disclosures. It contains forward-looking statements including, without limitation, statements relating to the company's plans, strategies, objectives, expectations, intentions, and resources that are made pursuant to the "safe harbor" provisions of the Private Securities Litigation Reform Act of 1995. The words "intends," "believes," "expects," "plans," "scheduled," "anticipates," "estimates," and similar expressions identify forward-looking statements. The company does not undertake to update, revise or correct any of the forward-looking information. Readers are cautioned that such forward-looking statements should be read in conjunction with the company's disclosures under the heading: "CAUTIONARY STATEMENT FOR THE PURPOSES OF THE 'SAFE HARBOR' PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995," beginning on page 58.

Results of Operations

Conoco and Phillips Merger

On August 30, 2002, Conoco Inc. (Conoco) and Phillips Petroleum Company (Phillips) combined their businesses by merging with wholly owned subsidiaries of a new company named ConocoPhillips (the merger). The merger was accounted for using the purchase method of accounting. Although the business combination of Conoco and Phillips was a merger of equals, generally accepted accounting principles required that one of the two companies in the transaction be designated as the acquirer for accounting purposes. Phillips was designated as the acquirer based on the fact that its former common stockholders initially held more than 50 percent of the ConocoPhillips common stock after the merger. Because Phillips was designated as the acquirer, its operations and results are presented in this annual report for all periods prior to the close of the merger. From the merger date forward, the operations and results of ConocoPhillips reflect the combined operations of the two companies.

As a condition of the merger, the U.S. Federal Trade Commission (FTC) required that the company divest specified Conoco and Phillips assets, the most significant of which were Phillips' Woods Cross, Utah, refinery and associated motor fuel marketing operations; Conoco's Commerce City, Colorado, refinery and related crude oil pipelines and Phillips' Colorado motor fuel marketing operations. All assets and operations that are required by the FTC to be divested are included in Corporate and Other as discontinued operations. Included in the results of discontinued operations in 2002 was a $69 million after-tax charge for the write-down to fair value of the Phillips operations to be disposed. Because the Conoco assets to be disposed of were recorded at fair value in the purchase price allocation, no further write-downs were required. Discontinued operations also include other, non-FTC mandated assets held for sale. See Note 4 — Discontinued Operations in the Notes to Consolidated Financial Statements for additional information, including a complete list of assets required by the FTC to be divested.

As a result of the merger, the company implemented a restructuring program in September 2002 to capture the synergies of combining Phillips and Conoco by eliminating redundancies, consolidating assets, and sharing common services and functions across regions. The restructuring program that was implemented in September 2002 is expected to be completed by the end of February 2004 and, through December 31, 2002, approximately 2,900 positions worldwide, most of which are in the United States, had been identified for elimination. Of this total, 775 employees were terminated by December 31, 2002. Associated with implementation of the restructuring program, ConocoPhillips accrued $770 million for merger-related restructuring and work force reduction liabilities in 2002. These liabilities primarily represent estimated termination payments and related employee benefits associated with the reduction in positions. These liabilities include $337 million related to Conoco operations, which was reflected in the purchase price allocation as an assumed liability, and $422 million ($253 million after-tax) related to Phillips operations that was charged to selling, general and administrative, and production and operating expenses; and $11 million before-tax included in discontinued operations. Of the above accruals, $598 million related primarily to severance benefits. Payments will be made to former Conoco and Phillips employees under each company's respective severance plans. During 2002, payments of $223 million were made, resulting in a year-end 2002 severance accrual balance of $375 million.

Also related to the merger and recorded in 2002 was a $246 million write-off of acquired in-process research and development costs related to Conoco's natural gas-to-liquids and other technologies. In accordance with Financial Accounting Standards Board (FASB) Interpretation No. 4, "Applicability of FASB Statement No. 2 to Business Combinations Accounted for by the Purchase Method," value assigned to research and development activities in the purchase price allocation that have no alternative future use should be charged to expense at the date of the consummation of the combination. The $246 million charge was recorded in the Emerging Businesses segment and was the same on both a before-tax and after-tax basis.

ConocoPhillips also accrued $22 million, after-tax, in 2002 for change-in-control costs associated with seismic contracts as a result of the merger. The expense was recorded in Corporate and Other and did not impact exploration expenses. In addition, the 2002 net loss also included transition costs of $36 million, bringing total after-tax merger-related costs to $557 million. See Note 3 — Merger of Conoco and Phillips in the Notes to Consolidated Financial Statements for additional information on the merger.

Consolidated Results

Years Ended December 31	Millions of Dollars		
	2002	2001	2000
Income from continuing operations	**$ 714**	1,611	1,848
Income (loss) from discontinued operations	**(993)**	32	14
Extraordinary items	**(16)**	(10)	—
Cumulative effect of accounting changes	**—**	28	—
Net income (loss)	**$(295)**	1,661	1,862

A summary of the company's net income (loss) by business segment follows:

Years Ended December 31	Millions of Dollars		
	2002	2001	2000
Exploration and Production (E&P)	**$1,749**	1,699	1,945
Midstream	**55**	120	162
Refining and Marketing (R&M)	**143**	397	238
Chemicals	**(14)**	(128)	(46)
Emerging Businesses	**(310)**	(12)	—
Corporate and Other*	**(1,918)**	(415)	(437)
Net income (loss)	**$ (295)**	1,661	1,862
**Includes income (loss) from discontinued operations of:*	***$ (993)***	*32*	*14*

2002 vs. 2001

ConocoPhillips incurred a net loss of $295 million in 2002, compared with net income of $1,661 million in 2001. The decrease was primarily attributable to recognizing impairments and loss accruals totaling $1,077 million after-tax associated with the company's retail and wholesale marketing operations that were classified as discontinued operations in late 2002, as well as merger-related costs totaling $557 million after-tax. Also negatively impacting results for 2002 were asset impairments totaling $192 million after-tax, lower refining margins, lower natural gas sales prices, decreased equity earnings from Duke Energy Field Services, LLC (DEFS), and higher interest expenses. These factors were partially offset by improved results from Chemicals and higher production volumes in E&P after the merger.

2001 vs. 2000

ConocoPhillips' net income was $1,661 million in 2001, an 11 percent decline from net income of $1,862 million in 2000. The decrease was primarily attributable to lower crude oil and natural gas liquids prices and lower results from the Chemicals business, partially offset by improved petroleum products margins, as well as the acquisition of Tosco Corporation (Tosco) in September 2001. See Note 6 — Acquisition of Tosco Corporation in the Notes to Consolidated Financial Statements for additional information on the acquisition. Also contributing to the lower results in 2001 was a decrease in the amount of gains on asset sales, compared with 2000, partially offset by lower property impairments in 2001.

Income Statement Analysis

2002 vs. 2001

In addition to the merger discussed previously, ConocoPhillips closed on the $7 billion acquisition of Tosco on September 14, 2001. Together, these transactions significantly increased operating revenues, purchase costs, operating expenses and other income statement line items. See Note 3 — Merger of Conoco and Phillips and Note 6 — Acquisition of Tosco Corporation in the Notes to Consolidated Financial Statements for additional information.

Sales and other operating revenues increased 128 percent in 2002. The increase was primarily attributable to increased product sales volumes due to the impact of the Tosco acquisition and the merger. These items were partially offset by lower natural gas sales prices in 2002 compared with 2001.

Equity in earnings of affiliates increased 537 percent in 2002. In addition to equity earnings from affiliates acquired in the merger for the last four months of 2002, equity earnings from Chevron Phillips Chemical Company LLC (CPChem) improved in 2002 as a result of improved margins. Partially offsetting these items were lower earnings in 2002 from DEFS and Merey Sweeny, L.P. (MSLP). DEFS' decline was primarily attributable to higher operating expenses, gas imbalance adjustments, and lower natural gas liquids prices, while MSLP's decline was mainly due to lower crude oil light-heavy differentials.

Other income increased 94 percent in 2002, mainly the result of a favorable revaluation and settlement of long-term incentive performance units held by former senior Tosco executives, as well as additional interest income following the merger. During 2002, the company recorded gains totaling $59 million before-tax, as the incentive performance units were marked-to-market each reporting period and eventually settled. See Note 6 — Acquisition of Tosco Corporation in the Notes to Consolidated Financial Statements for more information.

Purchased crude oil and products increased 176 percent in 2002. The increase reflects higher purchase volumes of crude oil and petroleum products resulting from the Tosco acquisition and the merger.

Production and operating expenses increased 89 percent in 2002, while selling, general and administrative (SG&A) expenses increased 171 percent. Both increases were primarily attributable to the Tosco acquisition and the merger. In conjunction with the merger, ConocoPhillips wrote off $246 million of acquired in-process research and development costs related to Conoco's natural gas-to-liquids and other technologies to production and operating expenses in 2002. ConocoPhillips also expensed $135 million in merger-related costs to production and operating expenses and $379 million to SG&A expenses in 2002.

Exploration expenses increased 93 percent in 2002. The increase reflects the merger, a $77 million leasehold impairment of deepwater Block 34, offshore Angola, and dry hole costs of $161 million in 2002, compared with $48 million in 2001.

Depreciation, depletion and amortization increased 65 percent in 2002, compared with 2001. The increase was primarily the result of an increased depreciable base of properties, plants and equipment following the merger and the Tosco acquisition.

During 2002, ConocoPhillips recorded property impairments totaling $49 million in connection with the sale of its Point Arguello assets, offshore California; two fields in the U.K. North Sea; and its interest in a non-producing field in Alaska. Impairment of tradenames ($102 million) was also recognized in the statement of operations in 2002. Property impairments recorded in 2001 consisted primarily of a

$23 million impairment of the Siri field, offshore Denmark. See Note 10 — Impairments in the Notes to Consolidated Financial Statements for additional information.

Taxes other than income taxes increased 153 percent in 2002, compared with 2001. The increase reflects higher excise taxes due to higher petroleum products sales and increased property and payroll taxes following the merger and the Tosco acquisition.

Environmental liabilities assumed in acquisitions and mergers are recorded as liabilities at discounted amounts — i.e. the total future estimated cost is determined, then discounted back to current dollars using a time-value-of-money concept. Over time the liability is increased by accretion to reflect the time value of money. Accretion on discounted liabilities increased 214 percent in 2002, reflecting the impact of the environmental liabilities assumed in the Tosco acquisition and the merger.

Interest expense increased 67 percent in 2002, mainly due to higher debt levels following the Tosco acquisition and the merger. Foreign currency losses of $24 million were recorded in 2002, compared with losses of $11 million in 2001. Preferred dividend requirements decreased in 2002, reflecting the redemption of $300 million of preferred securities in May 2002.

The company's effective tax rate from continuing operations in 2002 was 67 percent, compared with 51 percent in 2001. The increase in the effective tax rate in 2002 was primarily the result of the write-off of in-process research and development costs without a corresponding tax benefit and a higher proportion of income in higher-tax-rate jurisdictions.

Losses from discontinued operations were $993 million in 2002, compared with income of $32 million in 2001. The 2002 amount includes after-tax impairments and loss accruals. See Note 4 — Discontinued Operations in the Notes to Consolidated Financial Statements for additional information.

2001 vs. 2000

On March 31, 2000, ConocoPhillips and Duke Energy Corporation contributed their midstream gas gathering, processing and marketing businesses to DEFS. Effective July 1, 2000, ConocoPhillips and ChevronTexaco Corporation contributed their chemicals businesses, excluding ChevronTexaco's Oronite business, to CPChem. Both of these joint ventures are being accounted for using the equity method of accounting, which significantly affects how these operations are reflected in ConocoPhillips' consolidated statement of operations. Under the equity method of accounting, ConocoPhillips' share of a joint venture's net income is recorded in a single line item on the statement of operations: "Equity in earnings of affiliates." Correspondingly, the other income statement line items (for example, operating revenues, operating costs, etc.) include activity related to these operations only up to the effective dates of the joint ventures.

Sales and other operating revenues increased 12 percent in 2001, primarily due to the Tosco acquisition and increased crude oil production. These items were partially offset by the use of equity-method accounting for the DEFS and CPChem joint ventures, as well as a reduction in revenues attributable to certain non-core assets sold at year-end 2000.

Equity in earnings of affiliated companies decreased 64 percent in 2001. In the 2001 period, ConocoPhillips incurred a before-tax equity loss from its investment in CPChem of $240 million. ConocoPhillips' equity earnings related to DEFS were higher in 2001, as a result of a full year's activity in 2001, compared with only nine months in 2000. Equity earnings in 2001 benefited from a full year's operations at MSLP, a 50-percent-owned equity company that owns and operates the coker unit at the Sweeny, Texas, refinery. Other income decreased 59 percent in 2001, primarily attributable to lower net gains on asset sales in 2001 compared with 2000.

Total costs and expenses increased 16 percent in 2001, compared with 2000. The increase was mainly the result of the Tosco acquisition, as well as a full year's ownership of the company's Alaskan E&P operations that were acquired in April 2000. These items were partially offset by the use of equity-method accounting for the DEFS and CPChem joint ventures, and lower crude oil acquisition costs at the company's refineries.

Segment Results

E&P

	2002	2001	2000
	Millions of Dollars		
Net Income			
Alaska	**$ 870**	866	829
Lower 48	**286**	476	559
United States	**1,156**	1,342	1,388
International	**593**	357	557
	$ 1,749	1,699	1,945
	Dollars Per Unit		
Average Sales Prices			
Crude oil (per barrel)			
United States	**$ 23.83**	23.57	28.83
International	**25.14**	24.16	28.42
Total consolidated	**24.38**	23.77	28.65
Equity affiliates	**18.41**	12.36	—
Worldwide	**24.07**	23.74	28.65
Natural gas — lease (per thousand cubic feet)			
United States	**2.75**	3.56	3.47
International	**2.79**	2.60	2.56
Total consolidated	**2.77**	3.23	3.13
Equity affiliates	**2.71**	—	—
Worldwide	**2.77**	3.23	3.13
Average Production Costs Per Barrel of Oil Equivalent			
United States	**$5.66**	5.52	5.27
International	**3.99**	2.70	2.85
Total consolidated	**4.94**	4.60	4.29
Equity affiliates	**4.38**	2.74	—
Worldwide	**4.92**	4.60	4.29
Finding and Development Costs Per Barrel of Oil Equivalent			
United States	**$7.46**	5.15	2.78
International*	**5.09**	6.80	1.17
Worldwide*	**5.57**	5.97	2.41

**Includes ConocoPhillips' share of equity affiliates.*

	Millions of Dollars		
Worldwide Exploration Expenses			
General administrative; geological and geophysical; and lease rentals	**$ 285**	207	168
Leasehold impairment	**146**	51	39
Dry holes	**161**	48	91
	$ 592	306	298

	2002	2001	2000
	Thousands of Barrels Daily		
Operating Statistics			
Crude oil produced			
Alaska	**331**	339	207
Lower 48	**40**	34	34
United States	**371**	373	241
Norway	**157**	117	114
United Kingdom	**39**	19	25
Canada	**13**	1	6
Other areas	**67**	51	51
Total consolidated	**647**	561	437
Equity affiliates	**35**	2	—
	682	563	437
Natural gas liquids produced			
Alaska	**24**	25	19
Lower 48	**8**	1	1
United States	**32**	26	20
Norway	**6**	5	5
United Kingdom	**2**	2	2
Canada	**4**	—	1
Other areas	**2**	2	1
	46	35	29
	Millions of Cubic Feet Daily		
Natural gas produced*			
Alaska	**175**	177	158
Lower 48	**928**	740	770
United States	**1,103**	917	928
Norway	**171**	130	136
United Kingdom	**424**	178	214
Canada	**165**	18	83
Other areas	**180**	92	33
Total consolidated	**2,043**	1,335	1,394
Equity affiliates	**4**	—	—
	2,047	1,335	1,394

**Represents quantities available for sale. Excludes gas equivalent of natural gas liquids shown above.*

	Thousands of Barrels Daily		
Mining operations			
Syncrude produced	**8**	—	—

2002 vs. 2001

Net income from ConocoPhillips' E&P segment increased 3 percent in 2002. Although E&P benefited from four months of increased production volumes in 2002 following the merger, this was mostly offset by lower natural gas sales prices, higher exploration expenses, and the unfavorable $24 million impact of a tax law change in the United Kingdom. ConocoPhillips' average worldwide crude oil sales price was $24.07 per barrel in 2002, a 1 percent increase over $23.74 in 2001. The company's average worldwide natural gas price in 2002 was $2.77 per thousand cubic feet, a 14 percent decrease from $3.23 in 2001. However, natural gas prices trended upward during 2002, with the company's December 2002 worldwide price averaging $3.51 per thousand cubic feet.

ConocoPhillips' proved reserves at year-end 2002 were 7.81 billion barrels of oil equivalent, a 52 percent increase over 5.13 billion barrels at year-end 2001. The increase was attributable to the merger.

2001 vs. 2000

Net income from ConocoPhillips' E&P segment decreased 13 percent in 2001, as the positive impact of increased crude oil production was more than offset by lower crude oil prices, and, to a lesser extent, lower natural gas production due mainly to asset dispositions in Canada. Benefiting 2000 net income was higher net gains on asset sales than in 2001. ConocoPhillips' average worldwide crude oil sales price was $23.74 per barrel in 2001, a 17 percent decrease from $28.65 in 2000. Natural gas prices began 2001 at historically high levels, but trended lower during the remainder of the year, with the company's December 2001 average price at $2.34 per thousand cubic feet.

ConocoPhillips' proved reserves at year-end 2001 were 5.13 billion barrels of oil equivalent, a 2 percent increase over 5.02 billion barrels at year-end 2000.

U.S. E&P

2002 vs. 2001

Net income from the company's U.S. E&P operations decreased 14 percent in 2002. Although net income for 2002 benefited from four months of increased production volumes following the merger, this was more than offset by lower natural gas prices, lower production volumes in Alaska, and higher dry hole costs. The company's U.S. average natural gas price in 2002 was 23 percent lower than 2001. However, natural gas prices trended upward during 2002, with the company's December 2002 average U.S. price at $3.66 per thousand cubic feet.

The company's U.S. crude oil production decreased slightly in 2002, while natural gas production increased 20 percent. The increase in natural gas production was mainly due to four months of production from fields acquired in the merger. The merger impact on total crude oil production was offset by lower production in Alaska, which experienced normal field declines, along with operating interruptions at the Prudhoe Bay field during the year. With a full year's combined production from both Conoco and Phillips operations, the company expects that its total U.S. oil and gas production volumes will increase in 2003 over those of 2002. ConocoPhillips' fourth quarter production volumes, which included a full period of combined operations, averaged 426,000 barrels per day of liquids and 1,548 million cubic feet per day of natural gas.

2001 vs. 2000

Net income from the company's U.S. E&P operations decreased 3 percent in 2001, compared with 2000. The 2001 results reflect a 55 percent increase in crude oil production, due to a full year's production from the Alaska operations acquired in April 2000, as well as increased production due to the startup of the Alpine field in Alaska in December 2000. The benefit of increased crude oil production was offset by lower U.S. crude oil prices, which declined 18 percent in 2001. U.S. natural gas production declined slightly in 2001, reflecting field declines and asset dispositions. Benefiting 2000 net income was a net gain on asset sales of $44 million — most of which was related to the disposition of the company's coal and lignite operations.

International E&P

2002 vs. 2001

Net income from the company's international E&P operations increased 66 percent in 2002. The improvement reflects four months of increased production volumes following the merger. However, 2002 net income included a $24 million deferred tax charge related to tax law changes in the United Kingdom. In April 2002, the U.K. government announced proposed changes to corporate tax laws specifically impacting the oil and gas industry and production from the U.K. sector of the North Sea. The proposed changes became law in July 2002. A 10 percent supplementary charge to corporation taxes is now assessed on profits, which is expected to be partially offset by the elimination of royalties and an increase in first-year deduction allowances for capital investments. Net income in 2002 also included a $77 million leasehold impairment of deepwater Block 34, offshore Angola, due to an unsuccessful exploratory well in the block, along with higher dry hole charges.

The company's international crude oil production increased 64 percent in 2002, while natural gas production increased 126 percent. The increases were mainly due to the addition of four months of production from fields acquired in the merger. With a full year's combined production from both Conoco and Phillips operations, the company expects that its total international oil and gas production volumes will increase in 2003 over those of 2002. ConocoPhillips' fourth quarter production volumes, which included a full period of combined operations, averaged 585,000 barrels per day of liquids and 1,994 million cubic feet per day of natural gas.

2001 vs. 2000

Net income from ConocoPhillips' international E&P operations decreased 36 percent in 2001. The decrease was primarily the result of lower crude oil and natural gas production volumes, as well as lower crude oil prices. Additionally, after-tax foreign currency gains of $2 million were included in international E&P's net income in 2001, compared with losses of $10 million in 2000. Net income in 2000 included a net gain on property dispositions of $118 million related to the disposition of the Zama area fields in Canada, partially offset by an $86 million impairment of the Ambrosio field in Venezuela.

International crude oil production declined 3 percent in 2001, mainly due to lower production in the U.K. North Sea, Venezuela and Canada, partly offset by increased production from Norway and Nigeria. Canadian and Venezuelan crude oil production declined relative to 2000 due to asset dispositions. Production in the U.K. North Sea decreased on normal field declines. Production from Norway improved in 2001 due to improved processing reliability and well workovers, while Nigerian production increased on development activities and higher quotas. International natural gas production declined 10 percent in 2001, primarily the result of the Canadian asset dispositions and lower U.K. North Sea output noted above, partially offset by higher production in Nigeria and new natural gas production from offshore western Australia.

Midstream

	2002	2001	2000
	Millions of Dollars		
Net Income	**$ 55**	120	162
	Dollars Per Barrel		
Average Sales Prices			
U.S. natural gas liquids*			
Consolidated	**$19.07**	—	—
Equity	**15.92**	18.77	21.83**
	Thousands of Barrels Daily		
Operating Statistics			
Natural gas liquids extracted	**156**	120	131***
Natural gas liquids fractionated	**133**	108	158

**Based on index prices from the Mont Belvieu and Conway market hubs that are weighted by natural gas liquids component and location mix.*

***Estimate based on ConocoPhillips' first quarter realized price and DEFS' index price for the remainder of the year.*

****Based on a weighted average of ConocoPhillips' volumes in the first quarter of 2000, and ConocoPhillips' share of DEFS volumes for the remainder of 2000.*

2002 vs. 2001

ConocoPhillips' Midstream segment consists of the company's 30.3 percent interest in Duke Energy Field Services, LLC (DEFS), as well as company-owned natural gas gathering and processing operations and natural gas liquids fractionation and marketing businesses. Net income from the Midstream segment decreased 54 percent in 2002. The decrease was primarily due to lower results from DEFS, which experienced a decline in natural gas liquids prices, increased costs for gas imbalance accruals and other adjustments, and higher operating expenses. These items were partially offset by the benefit of four month's results from operations acquired in the merger.

Included in the Midstream segment's net income in 2002 was a benefit of $35 million, representing the amortization of the basis difference between the book value of ConocoPhillips' contribution to DEFS and its 30.3 percent equity interest in DEFS. The corresponding amount for 2001 was $36 million. See Note 8 — Investments and Long-Term Receivables, in the Notes to Consolidated Financial Statements for additional information on the basis difference.

2001 vs. 2000

Net income from the Midstream segment decreased 26 percent in 2001, primarily the result of a 14 percent decline in natural gas liquids prices. In addition, the Midstream segment's results were affected by the lack of interest charges in the first quarter of 2000 prior to the formation of DEFS. DEFS incurs interest expense in connection with financing incurred upon formation to fund cash distributions to the parent entities. Prior to the formation of DEFS, the Midstream segment did not have interest expense. Included in the Midstream segment's net income in 2001 was a benefit of $36 million, representing the amortization of the basis difference between the book value of ConocoPhillips' contribution to DEFS and its 30.3 percent equity interest in DEFS. The corresponding amount for 2000 was $27 million.

R&M

	2002	2001	2000
	Millions of Dollars		
Net Income			
United States	**$ 138**	395	209
International	**5**	2	29
	$ 143	397	238
	Dollars Per Gallon		
U.S. Average Sales Prices*			
Automotive gasoline			
Wholesale	**$ .96**	.83	.92
Retail	**1.03**	1.01	1.07
Distillates — wholesale	**.77**	.78	.88

*Excludes excise taxes.

	2002	2001	2000
	Thousands of Barrels Daily		
Operating Statistics			
Refining operations*			
United States			
Rated crude oil capacity**	**1,829**	732	335
Crude oil runs	**1,661**	686	303
Capacity utilization (percent)	**91%**	94	90
Refinery production	**1,847**	795	365
International			
Rated crude oil capacity**	**195**	22	—
Crude oil runs	**152**	20	—
Capacity utilization (percent)	**78%**	91	—
Refinery production	**164**	19	—
Worldwide			
Rated crude oil capacity**	**2,024**	754	335
Crude oil runs	**1,813**	706	303
Capacity utilization (percent)	**90%**	94	90
Refinery production	**2,011**	814	365
Petroleum products sales volumes***			
United States			
Automotive gasoline	**1,147**	465	267
Distillates	**392**	170	107
Aviation fuels	**185**	78	41
Other products	**372**	220	50
	2,096	933	465
International	**162**	10	43
	2,258	943	508

*2002 includes ConocoPhillips' share of equity affiliates.
**Weighted-average crude oil capacity for the period, including the refineries acquired in the Tosco acquisition in September 2001 and the refineries acquired as a result of the merger. Actual capacity at year-end 2002 and 2001 was 2,166 thousand and 1,656 thousand barrels per day, respectively, in the United States and 440 thousand and 72 thousand barrels per day, respectively, internationally.
***Excludes spot market sales.

2002 vs. 2001

Net income from the R&M segment declined 64 percent in 2002, reflecting lower refining margins, along with an $84 million after-tax impairment of a tradename and leasehold improvements of certain retail sites. See Note 10 — Impairments in the Notes to Consolidated Financial Statements for additional information on these impairments. The R&M earnings for 2002 included four months' results from operations acquired in the merger, as well as the impact of a full year's results from Tosco operations, while the 2001 results included Tosco operations for only the last three and one-half months of 2001.

Worldwide crude oil refining capacity utilization was 90 percent in 2002, compared with 94 percent in 2001. The company's refineries produced 2,011,000 barrels per day of petroleum products in 2002, compared with 814,000 barrels per day in 2001. The increase reflects a full year of operations for refineries acquired in the Tosco acquisition and four months of operations for the refineries acquired in the merger.

2001 vs. 2000

Net income from the R&M segment increased 67 percent in 2001. On September 14, 2001, ConocoPhillips closed on the acquisition of Tosco. This transaction significantly increased the size of ConocoPhillips' R&M segment and benefited 2001 results. In addition to the Tosco acquisition, R&M's net income benefited from higher gasoline and distillates margins, particularly during the second quarter of 2001. Negatively affecting R&M results for the year were higher utility costs at the company's refineries, resulting from higher natural gas prices experienced in the first half of 2001.

Worldwide crude oil refining capacity utilization was 94 percent in 2001, compared with 90 percent in 2000. The company's refineries produced 814,000 barrels per day of petroleum products in 2001, compared with 365,000 barrels per day in 2000. The increase reflects the Tosco acquisition.

U.S. R&M

2002 vs. 2001

Net income from U.S. R&M operations declined 65 percent in 2002. The decrease was primarily due to lower refining margins, particularly in the Midcontinent and Gulf Coast regions, along with an $84 million after-tax impairment of a tradename and leasehold improvements of certain retail sites. See Note 10 — Impairments in the Notes to Consolidated Financial Statements for additional information on these impairments. These items were partially offset by increased production and sales volumes as a result of the Tosco acquisition and the merger. Net income for 2002 included four months from operations acquired in the merger, and a full year of Tosco operations, while the 2001 results included Tosco operations for only three and one-half months. Results for 2001 included a cumulative effect of a change in accounting principle that increased R&M net income by $26 million. Effective January 1, 2001, ConocoPhillips changed its method of accounting for the costs of major maintenance turnarounds from the accrue-in-advance method to the expense-as-incurred method. Also included in 2001 was a $27 million write-down of inventories to market value.

The crude oil capacity utilization rate for ConocoPhillips' U.S. refineries was 91 percent in 2002, compared with 94 percent in 2001. The lower utilization rate in 2002 reflects increased maintenance turnaround activity in 2002, the impact of tropical storms on the company's Gulf Coast refineries in the third quarter of 2002, and the impact of the loss of Venezuelan crude oil supply in the fourth quarter.

2001 vs. 2000

Net income from the R&M segment's U.S. operations increased 89 percent in 2001, compared with 2000. On September 14, 2001, ConocoPhillips closed on the acquisition of Tosco. This transaction significantly increased the size of ConocoPhillips' U.S. R&M operations and benefited 2001 net income.

In addition to the Tosco acquisition, R&M's earnings benefited from higher gasoline and distillates margins, particularly during the second quarter of 2001, and the accounting change discussed above. Negatively affecting R&M results for the year were higher utility costs at the company's refineries, resulting from higher natural gas prices experienced in the first half of 2001, as well as a $27 million write-down of inventories to market value. The Sweeny refinery's 2001 net income benefited from the coker unit that was started up in late 2000. The coker unit allows for the processing of heavier, lower-cost crude oil, which reduced crude oil purchase costs and contributed to the improved gasoline and distillates margins experienced during 2001.

ConocoPhillips' U.S. refineries (including those acquired in the Tosco acquisition since the acquisition date) processed an average of 686,000 barrels per day of crude oil in 2001, yielding a 94 percent capacity utilization rate. This compares with 303,000 barrels per day and a utilization rate of 90 percent in 2000. The Tosco acquisition accounted for 378,000 barrels per day in 2001.

International R&M

2002 vs. 2001

Net income from international R&M operations increased $3 million in 2002, reflecting the impact of the merger, which added one wholly owned and five joint-venture international refineries. A substantial part of ConocoPhillips' international R&M results are related to its Humber refinery in the United Kingdom, which had a 232,000 barrel per day crude oil processing capacity at December 31, 2002. This refinery was shut down for an extended period of time during the fourth quarter due to a power outage and subsequent downtime, which negatively impacted international R&M's 2002 results.

The crude oil capacity utilization rate for ConocoPhillips' international refineries was 78 percent in 2002, compared with 91 percent in 2001. The lower utilization rate in 2002 reflects the extended shutdown at the Humber refinery noted above.

2001 vs. 2000

Net income from the R&M segment's international operations decreased 93 percent in 2001, compared with 2000, reflecting the late-2000 disposition of the company's 50 percent interest in a refinery in Teesside, England. This was partially offset by the addition of the Whitegate refinery in Ireland as part of the Tosco acquisition in September 2001.

Chemicals

	2002	2001	2000
	Millions of Dollars		
Net Loss	**$ (14)**	(128)	(46)
	Millions of Pounds		
Operating Statistics			
Production*			
Ethylene	**3,217**	3,291	3,574
Polyethylene	**2,004**	1,956	2,230
Styrene	**887**	456	404
Normal alpha olefins	**592**	563	293

** Production volumes for periods after July 1, 2000, include ConocoPhillips' 50 percent share of Chevron Phillips Chemical Company LLC.*

2002 vs. 2001

ConocoPhillips' Chemicals segment consists of its 50 percent equity investment in CPChem, which was formed when the company and ChevronTexaco combined their worldwide chemicals businesses in July 2000.

The Chemicals segment incurred a net loss of $14 million in 2002, compared with a net loss of $128 million in 2001. The worldwide chemicals industry experienced an economic downturn beginning in the second half of 2000, and these difficult conditions remained present through 2001 and 2002. The downturn has been marked by decreased product demand and low product margins across key product lines. The smaller net loss in 2002 was primarily the result of higher margins due to lower operating expenses, feedstock costs and energy prices, partially offset by decreased sales prices.

A fire caused the shutdown of styrene production at CPChem's St. James, Louisiana, facility in February 2001. Production was restored in October 2001. Production volumes for other major product lines were comparable between 2002 and 2001.

The net loss in 2001 included several asset retirements and impairments totaling $84 million after-tax because of depressed economic conditions. A developmental reactor at the Houston Chemical Complex in Pasadena, Texas, was retired; property impairments were recorded on two polyethylene reactors at the Orange chemical plant in Orange, Texas; an ethylene unit was retired at the Sweeny complex in Old Ocean, Texas; an equity affiliate of CPChem recorded a property impairment related to a polypropylene facility; property impairments were taken on the manufacturing facility in Puerto Rico; and the benzene and cyclohexane units at the Puerto Rico facility were retired. In addition, the valuation allowance on the Puerto Rico facility's deferred tax asset related to its net operating losses was increased in 2001 so that the deferred tax assets were fully offset by valuation allowances. Partially offsetting these impairments was a business interruption insurance settlement recorded by CPChem and a favorable deferred tax adjustment, related to the tax basis of its investment, recorded by ConocoPhillips that resulted from an impairment related to the Puerto Rico facility, together totaling $57 million after-tax.

2001 vs. 2000

The Chemicals segment incurred a net loss of $128 million in 2001, compared with a net loss of $46 million in 2000. Global conditions for the chemicals and plastics industry were extremely difficult in 2001. Worldwide economic slowdowns, including a recessionary economy in the United States, led to decreased product demand and low product margins across many key product lines. CPChem's results were negatively affected by low ethylene, polyethylene and aromatics margins, as well as lower ethylene and polyethylene production. In addition to low margins and production volumes, 2001 contained interest charges incurred by CPChem that were not present in the first six months of 2000 prior to the formation of CPChem.

The difficult marketing environment led to several asset retirements and impairments being recorded by CPChem in 2001. Partially offsetting these impairments was a business interruption insurance settlement recorded by CPChem and a favorable deferred tax adjustment recorded by ConocoPhillips that resulted from the Puerto Rico facility impairment, together totaling $57 million after-tax.

The net loss for 2000 included ConocoPhillips' share of a property impairment that CPChem recorded in the fourth quarter related to its Puerto Rico facility. The impairment was required due to the deteriorating outlook for future paraxylene market conditions and a shift in strategic direction at the facility. In addition, a valuation allowance was recorded against a related deferred tax asset. Combined, these two items resulted in a non-cash $180 million after-tax charge to CPChem's earnings. ConocoPhillips' share was $90 million.

Emerging Businesses

	Millions of Dollars		
	2002	2001	2000
Net Loss			
Carbon fibers	**$ (15)**	—	—
Fuels technology	**(16)**	(12)	—
Gas-to-liquids	**(273)**	—	—
Power generation and other	**(6)**	—	—
	$ (310)	(12)	—

2002 vs. 2001

The Emerging Businesses segment includes the development of new businesses beyond the company's traditional operations. Emerging Businesses include carbon fibers, natural gas-to-liquids technology, fuels technology and power generation. Prior to the merger, this segment only included Phillips' fuels technology business.

The Emerging Businesses segment posted a net loss of $310 million in 2002, compared with a net loss of $12 million in 2001. Results for 2002 included a $246 million write-off of acquired in-process research and development costs related to Conoco's natural gas-to-liquids and other technologies. In accordance with FASB Interpretation No. 4, "Applicability of FASB Statement No. 2 to Business Combinations Accounted for by the Purchase Method," value assigned to research and development activities in the purchase price allocation that have no alternative future use should be charged to expense at the date of the consummation of the combination. The $246 million charge was the same on both a before-tax and after-tax basis, as there was no tax basis to the assigned value prior to its write-off. The increased number of developing businesses after the merger also contributed to the larger losses in 2002.

ConocoPhillips announced in February 2003 that it will shut down its carbon fibers project, as a result of market, operating and technology uncertainties. At the time of the merger, the company identified these uncertainties facing the carbon fibers project and initiated a strategic update for the new management of the company. In early 2003, the strategic update was completed and management made the decision to shut down the project. In the preliminary purchase price allocation, the company valued the carbon fibers technology at an amount equal to the plant construction costs. In the first quarter of 2003, the company will reduce the preliminary purchase price allocation associated with this project and accrue for shutdown, severance and other related costs that will result in a corresponding net increase in goodwill of $125 million.

2001 vs. 2000

In 2001, the Emerging Businesses segment included the company's development of new fuels technologies. Prior to 2001, these activities were not separately identifiable, and were included in the R&M segment.

Corporate and Other

	Millions of Dollars		
	2002	2001	2000
Net Loss			
Net interest	**$ (396)**	(262)	(278)
Corporate general and administrative expenses	**(173)**	(114)	(87)
Discontinued operations	**(993)**	32	14
Merger-related costs	**(307)**	—	—
Other	**(49)**	(71)	(86)
	$(1,918)	(415)	(437)

2002 vs. 2001

Net interest represents interest expense, net of interest income and capitalized interest. Net interest increased 51 percent in 2002, mainly due to higher debt levels following the Tosco acquisition and the merger of Conoco and Phillips.

Corporate general and administrative expenses increased 52 percent in 2002, primarily due to the impact of the merger. In addition, 2002 also included higher benefit-related costs, primarily from the accelerated vesting of awards under certain long-term compensation plans that occurred at the time of stockholder approval of the merger.

Losses from discontinued operations were $993 million in 2002, compared with income of $32 million in 2001. The 2002 amount included after-tax impairments and loss accruals of $1,077 million associated with the assets held for sale. See Note 4 — Discontinued Operations in the Notes to Consolidated Financial Statements for additional information on the impairments and loss accruals, as well as a description of the assets included in discontinued operations.

Merger-related costs in 2002 included restructuring accruals of $252 million, primarily related to work force reduction charges; change-in-control costs associated with seismic contracts totaling $22 million; and other transition costs of $33 million. Other merger-related costs of $250 million were recorded by the operating segments, bringing total merger-related costs to $557 million after-tax.

The category "Other" consists primarily of items not directly associated with the operating segments on a stand-alone basis, including captive insurance operations, certain foreign currency gains and losses, the tax impact of consolidations, and dividends on the preferred securities of the Phillips 66 Capital Trusts I and II. Results from Other were improved in 2002 primarily due to more favorable foreign currency transactions, and a favorable revaluation and settlement of certain long-term incentive units that were converted into Phillips performance units held by former senior Tosco executives, none of whom are employees of ConocoPhillips. Included in 2002 and 2001 were extraordinary losses on the early retirement of debt totaling $16 million and $10 million, respectively.

2001 vs. 2000

Corporate and Other net loss decreased 5 percent in 2001, compared with 2000, primarily due to lower net interest expense and improved results from discontinued operations partially offset by higher staff costs, contributions, corporate advertising and corporate transportation costs.

Capital Resources and Liquidity

Financial Indicators

	Millions of Dollars Except as Indicated		
	2002	2001	2000
Current ratio	**.9**	1.3	.8
Total debt repayment obligations due within one year	**$ 849**	44	262
Total debt	**$19,766**	8,654	6,884
Mandatorily redeemable preferred securities of trust subsidiaries	**$ 350**	650	650
Other minority interests	**$ 651**	5	1
Common stockholders' equity	**$29,517**	14,340	6,093
Percent of total debt to capital*	**39%**	37	51
Percent of floating-rate debt to total debt	**12%**	20	17

**Capital includes total debt, mandatorily redeemable preferred securities, other minority interests and common stockholders' equity. Expected new accounting rules in 2003 likely will cause mandatorily redeemable preferred securities to be presented as a liability. The increase in ConocoPhillips' debt-to-capital ratio from December 31, 2001, to December 31, 2002, resulted primarily from the merger. In addition to $12 billion of Conoco debt assumed, purchase accounting required the debt to be recorded at fair value at the time of the merger, increasing total debt by an additional $565 million.*

Significant Sources of Capital

During 2002, cash of $4,969 million was provided by operating activities, an increase of $1,407 million from 2001. Cash provided by operating activities before changes in working capital increased $54 million compared with 2001, primarily due to higher dividends from equity affiliates, higher crude oil prices and higher crude oil and natural gas volumes, offset by lower natural gas prices, lower refining margins, higher interest expenses and merger-related costs. Positive working capital changes of $1,184 million were primarily due to an increase in accounts payable, an increase in taxes and other accruals and a decrease in inventories, partially offset by increased receivables. Discontinued operations provided $202 million of operating cash flows in 2002, an increase of $169 million compared to 2001. The increase in 2002 was primarily due to 2002 including a full year of cash flow from a portion of assets acquired in the Tosco acquisition that are now included in discontinued operations.

During 2002, cash and cash equivalents increased $165 million. In addition to the cash provided by operating activities, $815 million was received from the sale of various ConocoPhillips assets; including the sale of exploration and production assets in the Netherlands, assets in Canada and propane terminal assets at Jefferson City, Missouri, and East St. Louis, Illinois. Funds were used to support the company's ongoing capital expenditures program, repay debt and pay dividends. In October 2002, ConocoPhillips' Board of Directors declared a dividend of $.40 per share, payable December 2, 2002, which represented an 11 percent increase in the quarterly dividend.

To meet its liquidity requirements, including funding its capital program, paying dividends and repaying debt, the company looks to a variety of funding sources, primarily cash generated from operating activities. By the end of 2004, however, the company anticipates raising funds of $3 billion to $4 billion, of which approximately $600 million had been raised as of December 31, 2002, from the sale of assets, including those assets required by the FTC to be sold. In December 2002, ConocoPhillips entered into an agreement to sell its Woods Cross refinery and associated marketing assets, subject to state and federal regulatory approvals. Also in December 2002, the company committed to and initiated a plan to sell a substantial portion of its U.S. company-owned retail sites.

While the stability of the company's cash flows from operating activities benefits from geographic diversity and the effects of upstream and downstream integration, the company's operating cash flows remain exposed to the volatility of commodity crude oil and natural gas prices and downstream margins, as well as periodic cash needs to finance tax payments and crude oil, natural gas and petroleum product purchases. The company's primary funding source for short-term working capital needs is a $4 billion commercial paper program, a portion of which may be denominated in euros (limited to euro 3 billion), supported by $4 billion in revolving credit facilities. Commercial paper maturities are generally kept within 90 days. At December 31, 2002, ConocoPhillips had $1,517 million of commercial paper outstanding, of which $206 million was denominated in foreign currencies.

Effective October 15, 2002, ConocoPhillips entered into two new revolving credit facilities to replace the previously existing $2.5 billion Conoco credit facilities, and also amended and restated a prior Phillips revolving credit facility to include ConocoPhillips as a borrower. The company now has a $2 billion 364-day revolving credit facility expiring on October 14, 2003, and two revolving credit facilities totaling $2 billion expiring in October 2006. There were no outstanding borrowings under any of these facilities at December 31, 2002. These credit facilities support the company's $4 billion commercial paper program. ConocoPhillips' Norwegian subsidiary has two $300 million revolving credit facilities that expire in June 2004, under which no borrowings were outstanding as of December 31, 2002.

In addition to the bank credit facilities, ConocoPhillips sells certain credit card and trade receivables to two Qualifying Special Purpose Entities (QSPEs) in revolving-period securitization arrangements. These arrangements provide for ConocoPhillips to sell, and the QSPEs to purchase, certain receivables and for the QSPEs to then issue beneficial interests of up to $1.5 billion to five bank-sponsored entities. At December 31, 2002 and 2001, the company had sold accounts receivable of $1.3 billion and $940 million, respectively. The receivables sold have been sufficiently isolated from ConocoPhillips to qualify for sales treatment. All five bank-sponsored entities are multi-seller conduits with access to the commercial paper market and purchase interests in similar receivables from numerous other companies unrelated to ConocoPhillips. ConocoPhillips has no ownership in any of the bank-sponsored entities and has no voting influence over any bank-sponsored entity's operating and financial decisions. As a result, ConocoPhillips does not consolidate any of these entities. Beneficial interests retained by ConocoPhillips in the pool of receivables held by the QSPEs are subordinate to the beneficial interests issued to the bank-sponsored entities and were measured and recorded at fair value based on the present value of future expected cash flows estimated using management's best estimates concerning the receivables performance, including credit losses and dilution discounted at a rate commensurate with the risks involved to arrive at present value. These assumptions are updated periodically based on actual credit loss experience and market interest rates. ConocoPhillips also retains servicing responsibility related to the sold receivables. The fair value of the servicing responsibility approximates adequate compensation for the servicing costs incurred. ConocoPhillips' retained interest in the sold receivables at December 31, 2002 and 2001, was $1.3 billion and $450 million, respectively. Under accounting principles generally accepted in the United States, the QSPEs are not consolidated by ConocoPhillips. ConocoPhillips retained interest in sold receivables is reported on the balance sheet in accounts and notes receivable. See Note 13 — Sales of Receivables in the Notes to Consolidated Financial Statements for additional information.

On October 9, 2002, ConocoPhillips issued $2 billion of senior unsecured debt securities, consisting of $400 million 3.625% notes due 2007, $1 billion 4.75% notes due 2012, and $600 million 5.90% notes due 2032. The $1,980 million net proceeds of the offering were used to reduce commercial paper, to retire Conoco's $500 million floating rate notes due October 15, 2002, and for general corporate purposes.

Moody's Investor Service has assigned a rating of A3 on ConocoPhillips' senior long-term debt; and Standard and Poors and Fitch have assigned a rating of A-. ConocoPhillips does not have any ratings triggers on any of its corporate debt that would cause an automatic event of default in the event of a downgrade of ConocoPhillips' debt rating and thereby impacting ConocoPhillips' access to liquidity. In the event that ConocoPhillips' credit were to deteriorate to a level that would prohibit ConocoPhillips from accessing the commercial paper market, ConocoPhillips would still be able to access funds under its $4.6 billion revolving credit facilities. Based on ConocoPhillips' year-end commercial paper balance of $1.5 billion, ConocoPhillips had access to $3.1 billion in borrowing capacity as of December 31, 2002, after repaying all outstanding commercial paper, which provides ample liquidity to cover any needs that its businesses may require to cover daily operations.

Other Financing and Off-Balance Sheet Arrangements

During 1996 and 1997, ConocoPhillips formed two statutory business trusts, Phillips 66 Capital I and Phillips 66 Capital II. The company owns all of the common securities of the trusts and the trusts are consolidated by the company. The trusts exist for the sole purpose of issuing preferred securities to outside investors, and investing the proceeds thereof in an equivalent amount of subordinated debt securities of ConocoPhillips. The two trusts were established to raise funds for general corporate purposes. The subordinated debt securities of ConocoPhillips held by the trusts are eliminated in consolidation. The $300 million of 8.24% Trust Originated Preferred Securities issued by Phillips 66 Capital Trust I became callable, at par, $25 per share, during May 2001. On May 31, 2002, ConocoPhillips redeemed all of its outstanding subordinated debt securities held by the Trust, which triggered the redemption of the $300 million of trust preferred securities at par value, $25 per share. The redemption was funded by the issuance of commercial paper. The remaining $350 million of mandatorily redeemable preferred trust securities issued by Phillips 66 Capital Trust II are mandatorily redeemable in 2037, when the subordinated debt securities of ConocoPhillips held by the trust are required to be repaid. The mandatorily redeemable preferred securities are presented in the mezzanine section of the balance sheet. See Note 17 — Preferred Stock and Other Minority Interests in the Notes to Consolidated Financial Statements.

ConocoPhillips also had outstanding, at December 31, 2002, $645 million of equity held by minority interest owners, which provide a preferred return to those minority interest holders. In 1999, Conoco formed Conoco Corporate Holdings L.P. by contributing an office building and four aircraft. The limited partner interest was sold to Highlander Investors L.L.C. for $141 million, which represented an initial net 47 percent interest. Highlander is entitled to a cumulative annual priority return on its investment of 7.86 percent. The net minority interest in Conoco Corporate Holdings was $141 million at December 31, 2002, and is mandatorily redeemable in 2019 or callable without penalty beginning in the fourth quarter of 2004. In 2001, Conoco and Cold Spring Finance S.a.r.l. formed Ashford Energy Capital S.A. through the contribution of cash and a Conoco subsidiary promissory note. Cold Spring Finance S.a.r.l. held a $504 million net minority interest in Ashford Energy at December 31, 2002, and is entitled to a cumulative annual preferred return on its investment, based on three-month LIBOR rates plus 1.27 percent. The preferred return at December 31, 2002, was 2.70 percent. These minority interests are presented in the mezzanine section of the balance sheet. See Note 17 — Preferred Stock and Other Minority Interests in the Notes to Consolidated Financial Statements.

In January 2003, the FASB issued Interpretation No. 46, "Consolidation of Variable Interest Entities," and later in 2003, the FASB is expected to issue Statement of Financial Accounting Standards (SFAS) No. 149, "Accounting for Certain Financial Instruments with Characteristics of Liabilities and Equity." The company is evaluating these new pronouncements to determine whether the amounts currently presented in the mezzanine section of the balance sheet will be required to be presented as debt or as equity on the balance sheet. See Note 27 — New Accounting Standards and Note 28 — Variable Interest Entities in the Notes to Consolidated Financial Statements for more information.

The company leases ocean transport vessels, drillships, tank railcars, corporate aircraft, service stations, computers, office buildings, certain refining equipment, and other facilities and equipment. Prior to the acquisition of Tosco and the merger, the company had in place leasing arrangements for tankers, corporate aircraft and the construction of various retail marketing outlets. At December 31, 2002, approximately $730 million had been utilized under those arrangements, which is the total capacity available. At the time the company acquired Tosco, Tosco had in place previously arranged leasing arrangements for various retail stations and two office buildings in Tempe, Arizona. At December 31, 2002, approximately $1.3 billion had been utilized under those arrangements, which is the total capacity available. In addition, at the time of the merger, Conoco had in place leasing arrangements for certain refining equipment, two drillships, and various retail marketing outlets. At December 31, 2002, approximately $370 million had been utilized under those arrangements.

Several of the above leasing arrangements are with special purpose entities (SPEs) that are third-party trusts established by a trustee and funded by financial institutions. Other than those leasing arrangements, ConocoPhillips has no other direct or indirect relationship with the trusts or their investors. Each SPE from which ConocoPhillips leases assets is funded by at least 3 percent substantive, unaffiliated third-party, residual equity capital investment, which is at risk during the entire term of the lease. Changes in market interest rates do have an impact on the periodic amount of lease payments. ConocoPhillips has various purchase options to acquire the leased assets from the SPEs at the end of the lease term, but those purchase options are not required to be exercised by ConocoPhillips under any circumstances. If ConocoPhillips does not exercise its purchase option on a leased asset, the company does have guaranteed residual values, which are due at the end of the lease terms, but those guaranteed amounts would be reduced by the fair market value of the leased assets returned. These various leasing arrangements meet all requirements under generally accepted accounting principles to be treated as operating leases. However, in January 2003, the FASB issued Interpretation No. 46, "Consolidation of Variable Interest Entities," which will require consolidation in July 2003 of certain SPEs that were created prior to January 31, 2003, and which are still in existence at June 15, 2003. The company is evaluating the new Interpretation to determine whether the assets and debt of the leasing arrangements would be consolidated. See Note 28 — Variable Interest Entities in the Notes to Consolidated Financial Statements for more information. If the company is required to consolidate all of these entities, the assets of the entities and debt of approximately $2.4 billion would be required to be included in the consolidated financial statements. The company's maximum exposure to loss as a result of its involvement with the entities would be the debt of the entity less the fair value of the assets at the end of the lease terms. Of the $2.4 billion debt that would be consolidated, approximately $1.5 billion is associated with a major portion of the company's owned retail stores that the company has announced it plans to sell. As a result of the planned divestiture, the company plans to exercise purchase option provisions during 2003 and terminate various operating leases involving approximately 900 store sites and two office buildings. In addition, see Note 4 — Discontinued Operations in the Notes to Consolidated Financial Statements for details regarding the provisions for losses and penalties recorded in the fourth quarter, 2002 for the planned divestiture. Depending upon the timing of the company's exercise of these purchase options, and the determination of whether or not the lessor entities in these operating leases are variable interest entities requiring consolidation in 2003, some or all of these lessor entities could become consolidated subsidiaries of the company prior to the exercise of the purchase options and termination of the leases. See Note 14 — Guarantees and Note 19 — Non-Mineral Leases in the Notes to Consolidated Financial Statements.

During 2000, ConocoPhillips contributed its midstream gas gathering, processing and marketing business and its worldwide chemicals business to joint ventures with Duke Energy Corporation and ChevronTexaco Corporation, as successor to Chevron Corporation (ChevronTexaco), respectively, forming DEFS and CPChem, respectively. ConocoPhillips owns 30.3 percent of DEFS and 50 percent of CPChem, accounting for its interests in both companies using the equity method of accounting. The capital and financing programs of both of these joint-venture companies are intended to be self-funding.

DEFS supplies a substantial portion of its natural gas liquids to ConocoPhillips and CPChem under a supply agreement that continues until December 31, 2014. This purchase commitment is on an "if-produced, will-purchase" basis so it has no fixed production schedule, but has been, and is expected to be, a relatively stable purchase pattern over the term of the contract. Natural gas liquids are purchased under this agreement at various published market index prices, less transportation and fractionation fees. DEFS also purchases raw natural gas from ConocoPhillips' E&P operations.

ConocoPhillips and CPChem have multiple supply and purchase agreements in place, ranging in initial terms from four to 15 years, with extension options. These agreements cover sales and purchases of refined products, solvents, and petrochemical and natural gas liquids feedstocks, as well as fuel oils and gases. Delivery quantities vary by product, ranging from zero to 100 percent of production capacity at a particular refinery, most at the buyer's option. All products are purchased and sold under specified pricing formulas based on various published pricing indexes, consistent with terms extended to third-party customers.

In the second quarter of 2001, ConocoPhillips and its co-venturers in the Hamaca project secured approximately $1.1 billion in a joint debt financing for their heavy-crude oil project in Venezuela. The Export-Import Bank of the United States provided a guarantee supporting a 17-year-term $628 million bank facility. The joint venture also arranged a $470 million 14-year-term commercial bank facility for the project. Total debt of $947 million was outstanding under these credit facilities at December 31, 2002. ConocoPhillips, through the joint venture, holds a 40 percent interest in the Hamaca project, which is operated on behalf of the co-venturers by Petrolera Ameriven. The proceeds of these joint financings are being used to partially fund the development of the heavy-oil field and the construction of pipelines and a heavy-oil upgrader. The remaining necessary funding will be provided by capital contributions from the co-venturers on a pro rata basis to the extent necessary to successfully complete construction. Once completion certification is achieved, the joint project financings will become non-recourse with respect to the co-venturers and the lenders under those facilities can then look only to the Hamaca project's cash flows for payment.

MSLP is a limited partnership in which ConocoPhillips and PDVSA each own an indirect 50 percent interest. During 1999, MSLP issued $350 million of 8.85 percent bonds due 2019 that ConocoPhillips and PDVSA are joint-and-severally liable for under a construction completion guarantee. The bond proceeds were used to fund construction of a coker, vacuum unit and related facilities at the ConocoPhillips Sweeny refinery plus certain improvements to existing facilities at the same location. MSLP owns and operates the coker and vacuum unit and, in the third quarter of 2000, began processing long residue produced from the Venezuelan Merey crude oil delivered under a supply agreement that ConocoPhillips has with PDVSA. MSLP charges

ConocoPhillips a fee to process the long residue through the vacuum unit and coker. This is the partnership's primary source of revenue. If completion certification is not attained by 2004, the full debt is due. Upon completion certification, the 8.85 percent bonds become non-recourse to the two MSLP partners and the bondholders can then look only to MSLP cash flows for payment.

ConocoPhillips purchased the improvements to existing facilities from MSLP for a price equal to the cost of construction and MSLP provided seller financing. Terms of financing provide for 240 monthly payments of principal and interest commencing September 2000 with interest accruing at a 7 percent annual rate. The principal balance due on the seller financing was $131 million at December 31, 2002, and is included as long-term debt in ConocoPhillips' balance sheet. MSLP pays a monthly access fee to ConocoPhillips for the use of the improvements to the refinery. The access fee equals the monthly principal and interest paid by ConocoPhillips to purchase the improvements from MSLP. To the extent the access fee is not paid by MSLP, ConocoPhillips is not obligated to make payments for the improvements.

During the first quarter of 2002, MSLP issued $25 million of tax-exempt bonds due 2021. This issuance, combined with similar bonds MSLP issued in 1998, 2000, and 2001, bring the total outstanding to $100 million. As a result of the company's support as a primary obligor of a 50 percent share of these MSLP financings, $50 million and $38 million of long-term debt is included in ConocoPhillips' balance sheet at December 31, 2002, and December 31, 2001, respectively.

ConocoPhillips has transactions with many unconsolidated affiliates. Equity affiliate sales and services to ConocoPhillips amounted to $1,545 million in 2002, $1,110 million in 2001 and $1,347 million in 2000. Equity affiliate purchases from ConocoPhillips totaled $1,554 million in 2002, $935 million in 2001 and $1,573 million in 2000. These agreements were not the result of arms-length negotiations. However, ConocoPhillips believes that these contracts are generally at values that are similar to those that could be negotiated with independent third parties.

Capital Requirements

For information about ConocoPhillips' capital expenditures and investments, see "Capital Spending" below.

During 2002 and January 2003, ConocoPhillips redeemed the following notes and funded the redemptions with commercial paper:

- its $250 million 8.86% notes due May 15, 2022, at 104.43 percent;
- its $171 million 7.443% senior unsecured notes due 2004;
- its $250 million 8.49% notes due January 1, 2023, at 104.245 percent; and
- its $181 million SRW Cogeneration Limited Partnership note.

In addition, in April 2003, ConocoPhillips plans to redeem its $250 million 7.92% notes due in 2023 at 103.96 percent.

The following table summarizes the maturities of the drawn balances of the company's various debt instruments, as well as other non-cancelable, fixed or minimum, contractual commitments, as of December 31, 2002:

	Millions of Dollars				
	Payments Due by Period				
Debt and other non-cancelable cash commitments	Total	Up to 1 Year	2-3 Years	4-5 Years	After 5 Years
Total debt*	$19,766	849	2,667	3,827	12,423
Mandatorily redeemable other minority interests and preferred securities	491	—	—	—	491
Operating leases					
Minimum rental payments**	4,101	649	1,025	792	1,635
Sublease offsets	(641)	(129)	(165)	(83)	(264)
Unconditional throughput and processing fee and purchase commitments***	3,785	438	760	598	1,989

*Includes net unamortized premiums and discounts.

**Excludes $383 million in lease commitments that begin upon delivery of five crude oil tankers currently under construction. Delivery is expected in the third and fourth quarters of 2003.

***Represents non-market purchase commitments and obligations to transfer funds in the future for fixed or minimum amounts at fixed or minimum prices under various throughput or tolling agreements.

In addition to the above contractual commitments, the company has various guarantees that have the potential for requiring cash outflows resulting from a contingent event that could require company performance pursuant to a funding commitment to a third or related party. See Note 14 — Guarantees in the Notes to Consolidated Financial Statements for additional details. The following table summarizes the potential amounts and remaining time frames of these direct and indirect guarantees, as of December 31, 2002.

	Millions of Dollars				
	Amount of Expected Guarantee Expiration Per Period				
Direct and indirect guarantees	Total	Up to 1 Year	2-3 Years	4-5 Years	After 5 Years
Construction completion guarantees*	$ 859	418	441	—	—
Guaranteed residual values on leases**	$1,821	196	1,046	145	434
Guarantees of joint-venture debt***	355	54	74	8	219
Other guarantees and indemnifications****	662	121	141	37	363

*Amounts represent ConocoPhillips' maximum future potential payments under construction completion guarantees for debt and bond financing arrangements secured by the Hamaca and Merey Sweeny joint-venture projects in Venezuela and Texas, respectively. The debt is non-recourse to ConocoPhillips upon completion certification of the projects. Figures in the table represent maximum amount due under the guarantee in the event completion certification is not achieved. The Merey Sweeny debt is joint-and-several and included at its gross amount.

**Represents maximum additional amounts that would be due at the end of the term of certain operating leases if the fair value of the leased property was less than the guaranteed amount. See Note 19 — Non-Mineral Leases in the Notes to Consolidated Financial Statements.

***Represents amount of obligations directly guaranteed by the company in the event a guaranteed joint venture does not perform.

****Represents Merey Sweeny, L.P. agreement requirement to pay cash calls as required to meet minimum operating requirements of the venture, in the event revenues do not cover expenses over the next 18 years. Also includes certain potential payments related to two drillships, two LNG vessels, dealer and jobber loan guarantees to support the company's marketing business, a guarantee supporting a lease assignment on a corporate aircraft and guarantees of lease payment obligations for a joint venture. The maximum amount of future payments under tax and general indemnifications from normal ongoing operations is indeterminable.

Capital Spending

Capital Expenditures and Investments

	Millions of Dollars			
	2003 Budget	**2002**	2001	2000**
E&P				
United States — Alaska	$ 704	**706**	965	538
United States — Lower 48	780	**499**	389	413
International	3,433	**2,071**	1,162	726
	4,917	**3,276**	2,516	1,677
Midstream	23	**5**	—	17
R&M				
United States	881	**676**	423	217
International	250	**164**	5	—
	1,131	**840**	428	217
Chemicals	—	**60**	6	67
Emerging Businesses	248	**122**	—	—
Corporate and Other*	173	**85**	66	39
	$ 6,492	**4,388**	3,016	2,017
United States	$ 2,630	**2,043**	1,849	1,264
International	3,862	**2,345**	1,167	753
	$ 6,492	**4,388**	3,016	2,017
Discontinued operations	$ 60	**97**	69	5

*Excludes discontinued operations.
**Excludes the Alaskan acquisition.

ConocoPhillips' capital spending for continuing operations for the three-year period ending December 31, 2002, totaled $9.4 billion, excluding the purchase of ARCO's Alaskan businesses in 2000. The company's spending was primarily focused on the growth of its E&P business, with more than 79 percent of total spending for continuing operations in this segment. On March 31, 2000, ConocoPhillips contributed the gas gathering, processing and marketing portion of its then Midstream business to DEFS. On July 1, 2000, ConocoPhillips contributed its Chemicals business to CPChem. The capital programs of these joint-venture companies are intended to be self-funding.

Including approximately $400 million in capitalized interest and $200 million that will be funded by minority interests in the Bayu-Undan gas export project, ConocoPhillips' Board of Directors (Board) has approved $6.5 billion for capital projects and investments for continuing operations in 2003, a 48 percent increase over 2002 capital spending of $4.4 billion. The company plans to direct approximately 75 percent of its 2003 capital budget to E&P and about 17 percent to R&M. The remaining budget will be allocated toward emerging businesses, mainly power generation, and general corporate purposes, with a significant majority related to global integration of systems. Forty-one percent of the budget is targeted for projects in the United States. In addition to the above budget, ConocoPhillips expects to spend about $300 million to exercise purchase options for retail stores and office buildings, which are currently within various lease arrangements.

E&P

Capital spending for continuing operations for E&P during the three-year period ending December 31, 2002, totaled $7.5 billion. The expenditures over the three-year period supported several key exploration and development projects including:

- National Petroleum Reserve — Alaska (NPR-A) and satellite field prospects on Alaska's North Slope;
- the Hamaca heavy-oil project in Venezuela's Orinoco Oil Belt;
- the Peng Lai 19-3 discovery in China's Bohai Bay and additional Bohai Bay appraisal and satellite field prospects;
- the Kashagan field in the north Caspian Sea, offshore Kazakhstan;
- the Jade, Clair and CMS3 developments in the United Kingdom;
- the Bayu-Undan gas recycle project in the Timor Sea;
- acquisition of deepwater exploratory interests in Angola, Nigeria, Brazil, and the U.S. Gulf of Mexico;
- fields in Vietnam;
- Canadian conventional oil and gas projects, as well as expansion of the Syncrude project; and
- fields in Indonesia.

Capital expenditures for construction of the Endeavour Class tankers and an additional interest in the Trans-Alaska Pipeline System were also included in the E&P segment.

ConocoPhillips has contracted to build, for approximately $200 million each, five double-hulled Endeavour Class tankers for use in transporting Alaskan crude oil to the U.S. West Coast. During 2001, the Polar Endeavour, the first Endeavour Class tanker, entered service. The second tanker, the Polar Resolution, entered service in May 2002. The third tanker, the Polar Discovery, was christened on April 13, 2002, and is expected to enter service in 2003. ConocoPhillips expects to add a new Endeavour Class tanker to its fleet each year through 2005, allowing the company to retire older ships and cancel non-operated charters.

In 2002, the company and its co-venturers drilled or participated in 69 development wells at the Alaska Prudhoe Bay field. Also, new equipment was added to increase the efficiency of the field's existing water flood. At the Kuparuk field, 14 new development wells were added, and the Drill Site 3S (Palm) was installed earlier in the year. Production at Palm began in the fourth quarter. At Alpine, nine new development wells were added. Other capital spending at Alpine included facility improvements.

During the fourth quarter of 2001, heavy-crude-oil production began from the Hamaca project in Venezuela's Orinoco Oil Belt. Construction of an upgrader to convert heavy crude into a 26-degree API synthetic crude continues. Completion of the upgrader is expected in 2004. ConocoPhillips owns a 40 percent equity interest in the Hamaca project. ConocoPhillips' other heavy-oil project, Petrozuata, incurred no significant capital expenditures in 2002. In addition to the Hamaca development and Petrozuata, ConocoPhillips submitted a Declaration of Commerciality to the Venezuelan government on the Corocoro oil discovery in the fourth quarter of 2002. Development approval is expected in the first half of 2003, with expenditures to follow later in the year.

In 2002, development activities continued on the company's Peng Lai 19-3 discovery in Block 11/05 in China's Bohai Bay with production beginning late in the fourth quarter of 2002. Technical design activities for the second phase of development continued during 2002.

In 2002, ConocoPhillips and its co-venturers, in conjunction with the government of the Republic of Kazakhstan, declared the Kashagan field on the Kazakhstan shelf in the north Caspian Sea to be commercial. This declaration of commerciality enabled preparation of a development plan for the field. Drilling of the first of five planned appraisal wells was successfully completed in early 2002. Evaluation of test results continues on the second and third wells, drilling operations continue on the fourth, and testing continues on the fifth of these appraisal wells. In May 2002, ConocoPhillips, along with the other remaining co-venturers, completed the acquisition of proportionate interests of other co-venturers rights, which increased ConocoPhillips' ownership interest from 7.14 percent to 8.33 percent. In October 2002, ConocoPhillips and its co-venturers announced a new hydrocarbon discovery in the Kazakhstan sector of the Caspian Sea. An initial test well, the Kalamkas-1, flowed oil. This well is located adjacent to the Kashagan field.

In 2002, development of ConocoPhillips' Jade field, in the U.K. sector of the North Sea, continued with first production occurring in February 2002. A second production well was successfully drilled and began producing during the second quarter of 2002. In the second half of the year, two more production wells were completed and began producing. ConocoPhillips is the operator and holds a 32.5 percent interest in Jade. An exploration well was spudded late in 2002 and drilling operations are continuing into 2003.

In September 2002, ConocoPhillips began production from the Hawksley field in the southern sector of the U.K. North Sea. The Hawksley discovery well, 44/17a-6y, was completed in July 2002 in one of five natural gas reservoirs currently being developed by ConocoPhillips as a single, unitized project. The other reservoirs are McAdam, Murdoch K, Boulton, and Watt. Collectively, they are known as CMS3 due to their utilization of the production and transportation facilities of the ConocoPhillips-operated Caister Murdoch system (CMS). ConocoPhillips is the operator of CMS3 and holds a 59.5 percent interest.

ConocoPhillips' $1.9 billion gross Bayu-Undan gas-recycle project activities continued in the Timor Sea during 2002. This involved the drilling of future production wells from the wellhead platform and the installation of the platform jackets and all in-field flowlines. Fabrication and assembly of two large platform decks continues in Korea, as does work on the multi-product floating, storage and offtake vessel (FSO). At year-end, the project was approximately 69 percent complete. During mid-2003, the decks and FSO will be installed with first gas and commissioning commencing in the third quarter of 2003. Liquid sales will commence in early 2004 with production ramp-up occurring during the first six months of 2004. Activity associated with the Bayu-Undan gas export project, including a pipeline to Darwin and a liquefied natural gas plant, currently is focused on preparation of approval documentation and project design. Construction is expected to start in early 2003, following the Timor Sea Treaty ratification by Australia. ConocoPhillips' direct interest in the unitized Bayu-Undan field was 55.9 percent at year-end 2002. A further 8.25 percent interest was held through Petroz N.L., in which the company had an 89.7 percent stock ownership at year-end. ConocoPhillips has effective voting control over the pipeline and liquefied natural gas plant component of the gas export project and thus plans to consolidate that part of the Bayu-Undan project and present the other venturers as minority interests.

In 2002, ConocoPhillips continued pursuing the goal of increasing its presence in high-potential deepwater areas. ConocoPhillips was the high bidder in the central Gulf of Mexico sale for the Lorien prospect located in Green Canyon Block 199 and was officially awarded the block in 2002. In Brazil, ConocoPhillips acquired joint-venture partners for its two deepwater blocks and purchased additional seismic data. Plans for 2003 include the purchase of additional seismic data and the further evaluation of the two blocks' prospects. In May 2002, initial results showed that the first exploratory well drilled in Block 34, offshore Angola, was a dry hole. In view of this information, ConocoPhillips reassessed the fair value of the remainder of the block and determined that its investment in the block was impaired by $77 million, both before- and after-tax. Further technical analysis of the results of this first well continues. The second of three commitment wells in this block is scheduled for drilling in 2003.

ConocoPhillips entered into a production sharing contract on Oil Prospecting Lease (OPL) 318, deepwater Nigeria, on June 14, 2002, where ConocoPhillips is operator with 50 percent interest. The acquisition of 3-D seismic data on OPL 318 is planned to begin in 2003, with the first exploratory well expected to be drilled in the fourth quarter of 2004.

In the third quarter of 2002, production began from two new wellhead platforms in the Block 15-2 Rang Dong field in Vietnam. These additional platforms increased production from the field from under 6,800 to over 12,400 net barrels per day at year end 2002.

In Canada, total capital expended in 2002 was $136 million. Capital spending for conventional oil and gas properties was $75 million and Syncrude expansion continued with $54 million expended. In addition, the Mackenzie Delta/Parson's Lake project efforts focused on gaining pipeline regulatory approval and acquiring seismic data.

ConocoPhillips continued with the development of key gas fields in the Natuna Sea in Indonesia. Total spending on Block B gas development in the last four months of 2002 was $101 million, including investment in the Belanak floating, production, storage and offtake vessel and wellhead platform, plus wells and pipeline infrastructure required for the newly commenced gas sales to Petronas Malaysia.

ConocoPhillips acquired a 14 percent interest in PT Transportasi Gas Indonesia (TGI) in 2002. The primary assets of TGI are the Grissik-Duri pipeline, which has been in operation since 1998, and the Grissik-Singapore pipeline that is currently under construction with a completion date expected in late 2003. Total funding in 2002 was $54 million, which includes acquisition cost and capital expenditures.

Other capital spending for E&P during the three year-period ended December 31, 2002, supported:

- the Eldfisk waterflood development in Norway;
- the acquisition and development of coalbed-methane and conventional gas prospects and producing properties in the U.S. Lower 48; and
- North Sea prospects in the U.K. and Norwegian sectors, plus other Atlantic Margin wells in the United Kingdom, Greenland and the Faroe Islands.

2003 Capital Budget

E&P's 2003 capital budget for continuing operations is $4.9 billion, 50 percent higher than actual expenditures in 2002. Thirty percent of E&P's 2003 capital budget is planned for the United States. Of that, 47 percent is slated for Alaska.

ConocoPhillips has budgeted $461 million for worldwide exploration capital activities in 2003, with 28 percent of that amount, $131 million allocated for the United States. More than $41 million of the U.S. total will be directed toward the exploration program in Alaska, where wells are planned in the NPR-A and other locations on the North Slope. Outside the United States, significant exploration expenditures are planned in Kazakhstan, Venezuela, the United Kingdom and Norway.

The company plans to spend about $700 million in 2003 for its Alaskan operations. Large capital projects include the ongoing construction of three Endeavour Class tankers; development of the Meltwater, Palm and West Sak fields in the Greater Kuparuk area; development of the Borealis field in the Greater Prudhoe Bay area; as well as the exploratory activity discussed above.

In the Lower 48, capital expenditures will be focused on exploration and continued development of the company's acreage positions in the deepwater Gulf of Mexico, South Texas, the San Juan Basin, the Permian Basin, and the Texas Panhandle. Major deepwater developments include Magnolia, K2, and the Princess fields, while exploration continues using the drillship Pathfinder.

E&P is directing $3.4 billion of its 2003 capital budget to international projects. The majority of these funds will be directed to developing major long-term projects, including the Bayu-Undan liquids development and gas-recycling project in the Timor Sea, the Hamaca heavy-oil project and Corocoro development in Venezuela, additional development of oil and gas reserves in offshore Block B and onshore South Sumatra blocks in Indonesia, Blocks 15-1 and 15-2 in Vietnam, and Bohai Bay in China. In addition, funds will be used to expand the company's positions in the U.K. and Norwegian sectors of the North Sea, Syncrude operations in western Canada and to develop the Surmont heavy-oil project in Canada, and the Kashagan field in the Caspian Sea.

Costs incurred for the years ended December 31, 2002, 2001, and 2000, relating to the development of proved undeveloped oil and gas reserves were $1,631 million, $1,423 million, and $857 million, respectively. As of December 31, 2002, estimated future development costs relating to the development of proved undeveloped oil and gas reserves for the years 2003 through 2005 were projected to be $1,815 million, $939 million, and $539 million, respectively.

R&M

Capital spending for continuing operations for R&M during the three-year period ending December 31, 2002, was primarily for refinery-upgrade projects to improve product yields, to meet new environmental standards, to improve the operating integrity of key processing units, and to install advanced process control technology, as well as for safety projects.

Key significant projects during the three-year period included:

- construction of a polypropylene plant at the Bayway refinery in New Jersey;
- construction on a fluid catalytic cracking (FCC) unit at the Ferndale, Washington, refinery;
- expansion of the alkylation unit at the Los Angeles refinery;
- completion of a coker and continuous catalytic reformer at the company's Sweeny, Texas, refinery;
- capacity expansion and debottlenecking projects at the Borger, Texas, refinery;
- completion of a commercial S Zorb Sulfur Removal Technology (S Zorb) unit at the Borger refinery;
- an expansion of capacity in the Seaway crude-oil pipeline; and
- installation of advanced central control buildings and technologies at the Sweeny and Borger facilities.

Total capital spending for continuing operations for R&M for the three-year period was $1.5 billion, representing approximately 16 percent of ConocoPhillips' total capital spending for continuing operations.

During 2002, construction continued on two major projects: a polypropylene plant at the Bayway refinery in Linden, New Jersey, and an FCC unit at the Ferndale, Washington, refinery. The Bayway polypropylene plant will utilize propylene feedstock from the Bayway refinery to make up to 775 million pounds per year of polypropylene. The plant became operational in March 2003. The FCC unit at Ferndale is expected to be fully operational in the second quarter of 2003 and will enable the refinery to significantly improve gasoline production per barrel of crude input.

In 2002, ConocoPhillips made investments to improve its ability to meet regulatory "clean fuels" requirements throughout its refining system. The company plans to spend approximately $400 million per year for the next two years on clean fuels projects in the United States and already is well ahead of regulatory mandates for producing clean fuel in Europe. In 2002, ConocoPhillips completed a large continuous pilot plant demonstrating S Zorb for diesel, began construction of an S Zorb gasoline unit at its Ferndale, Washington, refinery, and announced its sixth licensing agreement for the use of S Zorb for gasoline and second licensing agreement for the use of S Zorb for diesel. The S Zorb process significantly reduces sulfur content in gasoline or diesel fuel for meeting new government regulations.

In 2002, a major expansion of the alkylation unit at the Los Angeles refinery was completed and as a result, production of non-MTBE (methyl tertiary-butyl ether) gasoline has increased.

2003 Capital Budget

R&M's 2003 capital budget for continuing operations is $1.1 billion, a 35 percent increase over spending of $840 million in 2002. Domestic spending is expected to consume about 80 percent of the R&M budget.

The company plans to direct about $750 million of the R&M capital budget to domestic refining, of which about 45 percent of the expenditures are related to clean fuels, safety and environmental projects. Domestic marketing, transportation and specialty businesses expect to spend about $130 million, with the remaining budget to fund projects in the company's international refining and marketing businesses in Europe and the Asia-Pacific region.

Emerging Businesses

Capital spending for Emerging Businesses during 2002 was primarily for construction of the Immingham combined heat and power cogeneration plant near the company's Humber refinery in the United Kingdom. Additional investments were made at a domestic power plant in Orange, Texas, and at the company's carbon fibers plant in Ponca City, Oklahoma.

Emerging Businesses' 2003 capital budget of $248 million is primarily dedicated to the continued construction of the Immingham combined heat and power cogeneration plant.

Contingencies

Legal and Tax Matters

ConocoPhillips accrues for contingencies when a loss is probable and the amounts can be reasonably estimated. Based on currently available information, the company believes that it is remote that future costs related to known contingent liability exposures will exceed current accruals by an amount that would have a material adverse impact on the company's financial statements.

All significant litigation arising from the June 23, 1999, flash fire that occurred in a reactor vessel at the K-Resin styrene-butadiene copolymer (SBC) plant at the Houston Chemical Complex has now been resolved.

On March 27, 2000, an explosion and fire occurred at the K-Resin SBC plant due to the overpressurization of an out-of-service butadiene storage tank. One employee was killed and several individuals, including employees of both ConocoPhillips and its contractors, were injured. Additionally, individuals who were allegedly in the area of the Houston Chemical Complex at the time of the incident have claimed they suffered various personal injuries due to exposure to the event. The wrongful death claim and the claims of the most seriously injured workers have been resolved. Currently, there are eight lawsuits pending on behalf of approximately 100 primary plaintiffs. Under the indemnification provisions of subcontracting agreements with Zachry and Brock Maintenance, Inc., ConocoPhillips sought indemnification from these subcontractors with respect to claims made by their employees. Although that plant was contributed to CPChem under the Contribution Agreement, ConocoPhillips retains liability for damages arising out of the incident.

Environmental

ConocoPhillips and each of its various businesses are subject to the same numerous international, federal, state, and local environmental laws and regulations as are other companies in the petroleum exploration and production; and refining, marketing and transportation of crude oil and refined products businesses. The most significant of these environmental laws and regulations include, among others, the:

- Federal Clean Air Act, which governs air emissions;
- Federal Clean Water Act, which governs discharges to water bodies;
- Federal Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), which imposes liability on generators, transporters, and arrangers of hazardous substances at sites where hazardous substance releases have occurred or are threatened to occur;
- Federal Resource Conservation and Recovery Act (RCRA), which governs the treatment, storage, and disposal of solid waste;
- Federal Oil Pollution Act of 1990 (OPA90) under which owners and operators of onshore facilities and pipelines, lessees or permittees of an area in which an offshore facility is located, and owners and operators of vessels are liable for removal costs and damages that result from a discharge of oil into navigable waters of the United States;
- Federal Emergency Planning and Community Right-to-Know Act (EPCRA) which requires facilities to report toxic chemical inventories with local emergency planning committees and responses departments;
- Federal Safe Drinking Water Act which governs the disposal of wastewater in underground injections wells; and
- U.S. Department of the Interior regulations, which relate to offshore oil and gas operations in U.S. waters and impose liability for the cost of pollution cleanup resulting from the lessee's operations and potential liability for pollution damages.

These laws and their implementing regulations set limits on emissions and, in the case of discharges to water, establish water quality limits. They also, in most cases, require permits in association with new or modified operations. These permits can require an applicant to collect substantial information in connection with the application process, which can be expensive and time-consuming. In addition, there can be delays associated with notice and comment periods and the agency's processing of the application. Many of the delays associated with the permitting process are beyond the control of the applicant.

Many states and foreign countries where ConocoPhillips operates also have, or are developing, similar environmental laws and regulations governing the same types of activities. While similar, in some cases these regulations may impose additional, or more stringent, requirements that can add to the cost and difficulty of marketing or transporting products across state and international borders.

The ultimate financial impact arising from environmental laws and regulations is neither clearly known nor easily determinable as new standards, such as air emission standards, water quality standards and stricter fuel regulations, continue to evolve. However, environmental laws and regulations are expected to continue to have an increasing impact on ConocoPhillips' operations in the United States and in most of the countries in which the company operates. Notable areas of potential impacts include air emission compliance and remediation obligations in the United States. Under the Clean Air Act, the EPA has promulgated a number of stringent limits on air emissions and established a federally mandated operating permit program. Violations of the Clean Air Act are enforceable with civil and criminal sanctions.

The EPA has also promulgated specific rules governing the sulfur content of gasoline, known generically as the "Tier II Sulfur Rules," which become applicable to ConocoPhillips' gasoline as early as 2004. The company is implementing a compliance strategy for meeting the requirements, including the use of ConocoPhillips' proprietary technology known as S Zorb. The company expects to use a combination of technologies to achieve compliance with these rules and has made preliminary estimates of its cost of compliance. These costs will be included in future budgeting for refinery compliance. The EPA has also promulgated sulfur content rules for highway diesel fuel that become applicable in 2006. ConocoPhillips is currently developing and testing an S Zorb system for removing sulfur from diesel fuel. It is anticipated that S Zorb will be used as part of ConocoPhillips' strategy for complying with these rules. Because the company is still evaluating and developing capital strategies for compliance with the rule, ConocoPhillips cannot provide precise cost estimates at this time, but will do so and report these compliance costs as required by law.

Additional areas of potential air-related impacts to ConocoPhillips are the proposed revisions to the National Ambient Air Quality Standards (NAAQS) and the Kyoto Protocol. In July 1997, the EPA promulgated more stringent revisions to the NAAQS for ozone and particulate matter. Since that time, final adoption of these revisions has been the subject of litigation (*American Trucking Association, Inc. et al. v. United States Environmental Protection Agency*) that eventually reached the U.S. Supreme Court during fall 2000. In February 2001, the U.S. Supreme Court remanded this matter, in part, to the EPA to address the implementation provisions relating to the revised ozone NAAQS. If adopted, the revised NAAQS could result in substantial future environmental expenditures for ConocoPhillips.

In 1997, an international conference on global warming concluded an agreement, known as the Kyoto Protocol, which called for reductions of certain emissions that contribute to increases in atmospheric greenhouse gas concentrations. The United States has not ratified the treaty codifying the Kyoto Protocol but may in the future. In addition, other countries where ConocoPhillips has interests, or may have interests in the future, have made commitments to the Kyoto Protocol and are in various stages of formulating applicable regulations. It is not, however, possible to accurately estimate the costs that could be incurred by ConocoPhillips to comply with such regulations, but such expenditures could be substantial.

ConocoPhillips also is subject to certain laws and regulations relating to environmental remediation obligations associated with current and past operations. Such laws and regulations include CERCLA and RCRA and their state equivalents. Remediation obligations include cleanup responsibility arising from petroleum releases from underground storage tanks located at numerous past and present ConocoPhillips owned and/or operated petroleum-marketing outlets throughout the United States. Federal and state laws require that contamination caused by such underground storage tank releases be assessed and remediated to meet applicable standards. In addition to other cleanup standards, many states have adopted cleanup criteria for MTBE for both soil and groundwater. MTBE standards continue to evolve, and future environmental expenditures associated with the remediation of MTBE-contaminated underground storage tank sites could be substantial.

RCRA requires permitted facilities to undertake an assessment of environmental conditions at the facility. If conditions warrant, ConocoPhillips may be required to remediate contamination caused by prior operations. In contrast to CERCLA, which is often referred to as "Superfund," the cost of corrective action activities under the RCRA corrective action program typically is borne solely by ConocoPhillips. Over the next decade, ConocoPhillips anticipates that significant ongoing expenditures for RCRA remediation activities may be required, but such annual expenditures for the near term are not expected to vary significantly from the range of such expenditures the company has experienced over the past few years. Longer term, expenditures are subject to considerable uncertainty and may fluctuate significantly.

ConocoPhillips from time to time receives requests for information or notices of potential liability from the EPA and state environmental agencies alleging that we are a potentially responsible party under CERCLA or an equivalent state statute. On occasion, ConocoPhillips also has been made a party to cost recovery litigation by those agencies or by private parties. These requests, notices and lawsuits assert potential liability for remediation costs at various sites that typically are not owned by ConocoPhillips but allegedly contain wastes attributable to the company's past operations. As of December 31, 2001, the company reported it had been notified of potential liability under CERCLA at 29 sites around the United States. The company also had been notified of potential liability under comparable state laws at 11 sites around the United States. At August 30, 2002, the date of the merger, Conoco had been notified of potential liability under CERCLA and comparable state laws at 24 sites around the United States. At seven of these sites, both Conoco and the company had been notified of potential liability. The resulting total for ConocoPhillips was 57 sites. At December 31, 2002, ConocoPhillips had resolved three of these sites and received four new notices of potential liability, leaving approximately 58 sites where ConocoPhillips has been notified of potential liability.

For most Superfund sites, ConocoPhillips' potential liability will be significantly less than the total site remediation costs because the percentage of waste attributable to ConocoPhillips versus that attributable to all other potentially responsible parties is relatively low. Although liability of those potentially responsible is generally joint and several for federal sites and frequently so for state sites, other potentially responsible parties at sites where ConocoPhillips is a party typically have had the financial strength to meet their obligations, and where they have not, or where potentially responsible parties could not be located, ConocoPhillips' share of liability has not increased materially. Many of the sites at which the company is potentially responsible are still under investigation by the EPA or the state agencies concerned. Prior to actual cleanup, those potentially responsible normally assess site conditions, apportion responsibility and determine the appropriate remediation. In some instances, ConocoPhillips may have no liability or attain a settlement of liability. Actual cleanup costs generally occur after the parties obtain EPA or equivalent state agency approval. There are relatively few sites where ConocoPhillips is a major participant, and neither the cost to ConocoPhillips of remediation at those sites nor such cost at all CERCLA sites in the aggregate is expected to have a material adverse effect on the competitive or financial condition of ConocoPhillips.

Expensed environmental costs were $546 million in 2002 and are expected to be approximately $687 million in 2003 and $717 million in 2004. Capitalized environmental costs were $325 million in 2002 and are expected to be approximately $638 million and $718 million in 2003 and 2004, respectively.

Remediation Accruals

ConocoPhillips accrues for remediation activities when it is probable that a liability has been incurred and reasonable estimates of the liability can be made. These accrued liabilities are not reduced for potential recoveries from insurers or other third parties and are not discounted (except, if assumed in a purchase business combination, such costs are recorded on a discounted basis). Many of these liabilities result from CERCLA, RCRA and similar state laws that require the company to undertake certain investigative and remedial activities at sites where it conducts, or once conducted, operations or at sites where ConocoPhillips-generated waste was disposed. The accrual also includes a number of sites identified by ConocoPhillips that may require environmental remediation, but which are not currently the subject of CERCLA, RCRA or state enforcement activities. If applicable, undiscounted receivables are accrued for probable insurance or other third-party recoveries. In the future, ConocoPhillips may incur significant costs under both CERCLA and RCRA. Considerable uncertainty exists with respect to these costs, and under adverse changes in circumstances, potential liability may exceed amounts accrued as of December 31, 2002.

Remediation activities vary substantially in duration and cost from site to site, depending on the mix of unique site characteristics, evolving remediation technologies, diverse regulatory agencies and enforcement policies, and the presence or absence of potentially liable third parties. Therefore, it is difficult to develop reasonable estimates of future site remediation costs.

At December 31, 2002, ConocoPhillips' balance sheet included a total environmental accrual of $743 million, compared with $439 million at December 31, 2001, an increase of $304 million, primarily resulting from the merger. The majority of these expenditures are expected to be incurred within the next 30 years.

Notwithstanding any of the foregoing and as with other companies engaged in similar businesses, environmental costs and liabilities are inherent in ConocoPhillips' operations and products, and there can be no assurance that material costs and liabilities will not be incurred. However, ConocoPhillips currently does not expect any material adverse effect upon its results of operations or financial position as a result of compliance with environmental laws and regulations.

Other

ConocoPhillips has deferred tax assets related to certain accrued liabilities, alternative minimum tax credits, and loss carryforwards. Valuation allowances have been established for certain foreign and state net operating loss carryforwards that reduce deferred tax assets to an amount that will, more likely than not, be realized. Uncertainties that may affect the realization of these assets include tax law changes and the future level of product prices and costs. Based on the company's historical taxable income, its expectations for the future, and available tax-planning strategies, management expects that the net deferred tax assets will be realized as offsets to reversing deferred tax liabilities and as reductions in future taxable income. The alternative minimum tax credit can be carried forward indefinitely to reduce the company's regular tax liability.

New Accounting Standards

There are a number of new FASB Statements of Financial Accounting Standards (SFAS) and Interpretations that ConocoPhillips implemented either in December 2002 or January 2003, as required: SFAS No. 143, "Accounting for Asset Retirement Obligations;" SFAS No. 145, "Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections;" SFAS No. 146, "Accounting for Costs Associated with Exit or Disposal Activities;" SFAS No. 148, "Accounting for Stock-Based Compensation — Transition and Disclosure;" Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others;" and Interpretation No. 46, "Consolidation of Variable Interest Entities." In addition, in 2003, the FASB is expected to issue SFAS No. 149, "Accounting for Certain Financial Instruments with Characteristics of Liabilities and Equity." For additional information about these, see Note 27 — New Accounting Standards in the Notes to Consolidated Financial Statements, which is incorporated herein by reference.

Critical Accounting Policies

The preparation of financial statements in conformity with generally accepted accounting principles requires management to select appropriate accounting policies and to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. See Note 1 — Accounting Policies in the Notes to Consolidated Financial Statements for descriptions of the company's major accounting policies. Certain of these accounting policies involve judgments and uncertainties to such an extent that there is a reasonable likelihood that materially different amounts would have been reported under different conditions, or if different assumptions had been used.

Oil and Gas Accounting

Accounting for oil and gas exploratory activity is subject to special accounting rules that are unique to the oil and gas industry. The acquisition of geological and geophysical seismic information, prior to the discovery of proved reserves, is expensed as incurred, similar to accounting for research and development costs. However, leasehold acquisition costs and exploratory well costs are capitalized on the balance sheet, pending determination of whether proved oil and gas reserves have been discovered on the prospect.

Property Acquisition Costs

For individually significant leaseholds, management periodically assesses for impairment based on exploration and drilling efforts to date. For leasehold acquisition costs that individually are relatively small, management exercises judgment and determines a percentage probability that the prospect ultimately will fail to find proved oil and gas reserves and pools that leasehold information with others in the geographic area. For prospects in areas that have had limited, or no, previous exploratory drilling, the percentage probability of ultimate failure is normally judged to be quite high. This judgmental percentage is multiplied by the leasehold acquisition cost, and that product is divided by the contractual period of the leasehold to determine a periodic leasehold impairment charge that is reported in exploration expense. This judgmental probability percentage is reassessed and adjusted throughout the contractual period of the leasehold based on favorable or unfavorable exploratory activity on the leasehold or on adjacent leaseholds, and leasehold impairment amortization expense is adjusted prospectively. By the end of the contractual period of the leasehold, the impairment probability percentage will have been adjusted to 100 percent if the leasehold is expected to be abandoned, or will have been adjusted to zero percent if there is an oil or gas discovery that is under development. See the supplemental Oil and Gas Operations disclosures about Costs Incurred and Capitalized Costs for more information about the amounts and geographic locations of costs incurred in acquisition activity, and the amounts on the balance sheet related to unproved properties.

Exploratory Costs

For exploratory wells, drilling costs are temporarily capitalized, or "suspended," on the balance sheet, pending a judgmental determination of whether potentially economic oil and gas reserves have been discovered by the drilling effort. This judgment usually is made within two months of the completion of the drilling effort, but can take longer, depending on the complexity of the geologic structure. Accounting rules require that this judgment be made at least within one year of well completion. If a judgment is made that the well did not encounter potentially economic oil and gas quantities, the well costs are expensed as a dry hole and are reported in exploration expense. Exploratory wells that are judged to have discovered potentially economic quantities of oil and gas and that are in areas where a major capital expenditure (e.g., a pipeline or offshore platform) would be required before production could begin, and where the economic viability of that major capital expenditure depends upon the successful completion of further exploratory work in the area, remain capitalized on the balance sheet as long as additional exploratory appraisal work is under way or firmly planned. For complicated offshore exploratory discoveries, it is not unusual to have exploratory wells remain suspended on the balance sheet for several years while the company performs additional appraisal drilling and seismic work on the potential oil and gas field. Unlike leasehold acquisition costs, there is no periodic impairment assessment of suspended exploratory well costs. Management continuously monitors the results of the additional appraisal drilling and seismic work and expenses the suspended well costs as dry holes when it judges that the potential field does not warrant further exploratory efforts in the near term. See the supplemental Oil and Gas Operations disclosures about Costs Incurred and Capitalized Costs for more information about the amounts and geographic locations of costs incurred in exploration activity and the amounts on the balance sheet related to unproved properties, as well as the Wells In Progress disclosure for the number and geographic location of wells not yet declared productive or dry.

Proved Oil and Gas Reserves

Engineering estimates of the quantities of recoverable oil and gas reserves in oil and gas fields are inherently imprecise and represent only approximate amounts because of the subjective judgments involved in developing such information. Despite the inherent imprecision in these engineering estimates, accounting rules require supplemental disclosure of "proved" oil and gas reserve estimates due to the importance of these estimates to better understanding the perceived value and future cash flows of a company's oil and gas operations. The judgmental estimation of proved oil and gas reserves is also important to the income statement because the proved oil and gas reserve estimate for a field serves as the denominator in the unit-of-production calculation of depreciation, depletion and amortization of the capitalized costs for that field. There are several authoritative guidelines regarding the engineering criteria that have to be met before estimated oil and gas reserves can be designated as "proved." The company's reservoir engineering department has policies and procedures in place that are consistent with these authoritative guidelines. The company has qualified and experienced internal engineering personnel who make these estimates. Proved reserve estimates are updated annually and take into account recent production and seismic information about each field. Also, as required by authoritative guidelines, the estimated future date when a field will be permanently shut-in for economic reasons is based on an extrapolation of oil and gas prices and operating costs prevalent at the balance sheet date. This estimated date when production will end affects the amount of estimated recoverable reserves. Therefore, as prices and cost levels change from year to year, the estimate of proved reserves also changes.

Canadian Syncrude Reserves

Canadian Syncrude proven reserves cannot be measured precisely. Reserve estimates of Canadian Syncrude are based on subjective judgments involving geological and engineering assessments of in-place crude bitumen volume, the mining plan, historical extraction recovery and upgrading yield factors, installed plant operating capacity and operating approval limits. The reliability of these estimates at any point in time depends on both the quality and quantity of the technical and economic data and the efficiency of extracting the bitumen and upgrading it into a light sweet crude oil. Despite the inherent imprecision in these engineering estimates, these estimates are used in determining depreciation expense.

Impairment of Assets

Long-lived assets used in operations are assessed for impairment whenever changes in facts and circumstances indicate a possible significant deterioration in the future cash flows expected to be generated by an asset group. If, upon review, the sum of the undiscounted pretax cash flows is less than the carrying value of the asset group, the carrying value is written down to estimated fair value. Individual assets are grouped for impairment purposes based on a judgmental assessment of the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets — generally on a field-by-field basis for exploration and production assets, at an entire complex level for downstream assets, or at a site level for retail stores. Because there usually is a lack of quoted market prices for long-lived assets, the fair value usually is based on the present values of expected future cash flows using discount rates commensurate with the risks involved in the asset group. The expected future cash flows used for impairment reviews and related fair value calculations are based on judgmental assessments of future production volumes, prices and costs, considering all available information at the date of review. See Note 10 — Impairments in the Notes to Consolidated Financial Statements.

Dismantlement, Removal and Environmental Costs

Under various contracts, permits and regulations, the company has material legal obligations to remove tangible equipment and restore the land or seabed at the end of operations at production sites. The largest asset removal obligations facing ConocoPhillips involve removal and disposal of offshore oil and gas platforms around the world, and oil and gas production facilities and pipelines in Alaska. The estimated undiscounted costs, net of salvage values, of dismantling and removing these facilities are accrued, using primarily the unit-of-production method, over the productive life of the asset. Estimating the future asset removal costs necessary for this accounting calculation is difficult. Most of these removal obligations are many years in the future and the contracts and regulations often have vague descriptions of what removal practices and criteria will have to be met when the removal event actually occurs. Asset removal technologies and costs are constantly changing, as well as political, environmental, safety and public relations considerations. See Note 11 — Accrued Dismantlement, Removal and Environmental Costs in the Notes to Consolidated Financial Statements.

Business Acquisitions

Purchase Price Allocation

Accounting for the acquisition of a business requires the allocation of the purchase price to the various assets and liabilities of the acquired business. For most assets and liabilities, purchase price allocation is accomplished by recording the asset or liability at its estimated fair value. The most difficult estimations of individual fair values are those involving properties, plants and equipment and identifiable intangible assets. The company uses all available information to make these fair value determinations and, for major business acquisitions, typically engages an outside appraisal firm to assist in the fair value determination of the acquired long-lived assets. The company has, if necessary, up to one year after the acquisition closing date to finish these fair value determinations and finalize the purchase price allocation.

Intangible Assets and Goodwill

In connection with the acquisition of Tosco Corporation on September 14, 2001, and the merger on August 30, 2002, the company recorded material intangible assets for tradenames, air emission permit credits, and permits to operate refineries. These intangible assets were determined to have indefinite useful lives and so are not amortized. This judgmental assessment of an indefinite useful life has to be continuously evaluated in the future. If, due to changes in facts and circumstances, management determines that these intangible assets then have definite useful lives, amortization will have to commence at that time on a prospective basis. As long as these intangible assets are judged to have indefinite lives, they will be subject to periodic lower-of-cost-or-market tests, which requires management's judgment of the estimated fair value of these intangible assets. See Note 6 — Acquisition of Tosco Corporation, Note 3 — Merger of Conoco and Phillips, and Note 10 — Impairments in the Notes to Consolidated Financial Statements.

Also in connection with the acquisition of Tosco and the merger, the company recorded a material amount of goodwill. Under the accounting rules for goodwill, this intangible asset is not amortized. Instead, goodwill is subject to annual reviews for impairment based on a two-step accounting test. The first step is to compare the estimated fair value of any reporting units within the company that have recorded goodwill with the recorded net book value (including the goodwill) of the reporting unit. If the estimated fair value of the reporting unit is higher than the recorded net book value, no impairment is deemed to exist and no further testing is required that year. If, however, the estimated fair value of the reporting unit is below the recorded net book value, then a second step must be performed to determine the amount of the goodwill impairment to record, if any. In this second step, the estimated fair value from the first step is used as the purchase price in a hypothetical new acquisition of the reporting unit. The various purchase business combination rules are followed to determine a hypothetical purchase price allocation for the reporting unit's assets and liabilities. The residual amount of goodwill that results from this hypothetical purchase price allocation is compared with the recorded amount of goodwill for the reporting unit, and the recorded amount is written down to the hypothetical amount if lower. Because quoted market prices for the company's reporting units are not available, management has to apply judgment in determining the estimated fair value of its reporting units for purposes of performing the first step of this periodic goodwill impairment test. Management uses all available information to make these fair value determinations and may engage an outside appraisal firm for assistance. In addition, if the first test step is not met, further judgment has to be applied in determining the fair values of individual assets and liabilities for purposes of the hypothetical purchase price allocation. Again, management has to use all available information to make these fair value determinations and may engage an outside appraisal firm for assistance. At year-end 2002, the estimated fair values of the company's domestic refining and marketing reporting units, excluding those acquired in the merger and those included in discontinued operations, were more than 10 percent higher than the recorded net book values (including the Tosco goodwill) of the reporting units. However, a lower fair value estimate in the future could result in impairment of the remaining $2.4 billion of Tosco goodwill. The allocation of goodwill attributable to the ConocoPhillips merger to reporting units, and its sensitivity to future impairment, will occur after the final allocation of the purchase price in 2003.

Inventory Valuation

Prior to the acquisition of Tosco in September 2001 and the merger in August 2002, the company's inventories on the last-in, first-out (LIFO) cost basis were predominantly reflected on the balance sheet at historical cost layers established many years ago, when price levels were much lower. Therefore, prior to 2001, the company's LIFO inventories were relatively insensitive to current price level changes. However, the acquisition of Tosco and the merger added LIFO cost layers that were recorded at replacement cost levels prevalent in late September 2001 and August 2002, respectively. As a result, the company's LIFO cost inventories are now much more sensitive to lower-of-cost-or-market impairment write-downs, whenever price levels fall. ConocoPhillips recorded a LIFO inventory lower-of-cost-or-market impairment in the fourth quarter of 2001 due to a crude oil price deterioration. While crude oil is not the only product in the company's LIFO pools, its market value is a major factor in lower-of-cost-or-market calculations. The company estimates that additional impairments could occur if a 60 percent/40 percent blended average of West Texas Intermediate/Brent crude oil prices falls below $21.75 per barrel at a reporting date. The determination of replacement cost values for the lower-of-cost-or-market test uses objective evidence, but does involve judgment in determining the most appropriate objective evidence to use in the calculations.

Projected Benefit Obligations

Determination of the projected benefit obligations for the company's defined benefit pension and postretirement plans are important to the recorded amounts for such obligations on the balance sheet and to the amount of benefit expense in the income statement. This also impacts the required company contributions into the plans. The actuarial determination of projected benefit obligations and company contribution requirements involves judgment about uncertain future events, including estimated retirement dates, salary levels at retirement, mortality rates, lump-sum election rates, rates of return on plan assets, future health care cost-trend rates, and rates of utilization of health care services by retirees. Due to the specialized nature of these calculations, the company engages outside actuarial firms to assist in the determination of these projected benefit obligations. For Employee Retirement Income Security Act-qualified pension plans, the actuary exercises fiduciary care on behalf of plan participants in the determination of the judgmental assumptions used in determining required company contributions into plan assets. Due to differing objectives and requirements between financial accounting rules and the pension plan funding regulations promulgated by governmental agencies, the actuarial methods and assumptions for the two purposes differ in certain important respects. Ultimately, the company will be required to fund all promised benefits under pension and postretirement benefit plans not funded by plan assets or investment returns, but the judgmental assumptions used in the actuarial calculations significantly affect periodic financial statements and funding patterns over time. Benefit expense is particularly sensitive to the discount rate and return on plan assets assumptions. A 1 percent decrease in the discount rate would increase annual benefit expense by $79 million, while a 1 percent decrease in the return on plan assets assumption would increase annual benefit expense by $21 million.

Outlook

As a condition to the merger, the U.S. Federal Trade Commission (FTC) required that both Conoco and Phillips divest certain assets. In the fourth quarter of 2002, the propane terminal assets at Jefferson City, Missouri, and East St. Louis, Illinois, were sold and ConocoPhillips agreed to sell its Woods Cross business unit in Salt Lake City, Utah, plus associated assets. See Note 4 — Discontinued Operations in the Notes to Consolidated Financial Statements for a list of the remaining assets held for sale.

In December 2002, ConocoPhillips committed to and initiated a plan to sell a substantial portion of its company-owned retail sites. In connection with the anticipated sale, the company, in the fourth quarter, recorded charges totaling $1,412 million before-tax, $1,008 million after-tax, primarily related to the impairment of properties, plants and equipment; goodwill; intangible assets and provision for losses and penalties to unwind various lease arrangements. The company expects to complete the sale of the sites in 2003.

In December of 2002, political unrest in Venezuela caused economic and other disruptions which shut down most oil production in Venezuela, including the company's Petrozuata, Hamaca and Gulf of Paria operations. At ConocoPhillips' Petrozuata joint venture, operations were closed down on December 15, 2002, due to shortages of hydrogen and natural gas (required for processing and fuel). Prior to the disruptions, Petrozuata was producing and processing approximately 120,000 gross (60,000 net) barrels of extra-heavy crude oil per day. Similarly, the disruptions have impacted development production and construction progress at the Hamaca joint-venture project. Construction of the Hamaca upgrader continues, although at a reduced rate. Difficulty in obtaining supplies has been the primary impediment. Production was shut in on December 6, 2002. Prior to the disruptions, Hamaca was producing approximately 55,000 gross (18,000 net) barrels of extra-heavy crude per day. In addition, the crude oil produced by Petrozuata is used as feedstock for ConocoPhillips' Lake Charles, Louisiana, refinery and a Venezuelan refinery operated by PDVSA. In December 2002, ConocoPhillips substituted about 1.2 million crude barrels for its Lake Charles refinery. At the company's Sweeny refinery, crude throughputs were reduced slightly due to short supply of Merey Venezuelan crude oil. Overall, there was minimum impact to net income; however, it could reduce net income $30 million to $50 million per month in 2003 as long as production at Petrozuata and Hamaca is shut in. Limited production began from Hamaca and Petrozuata in February 2003.

On March 12, 2002, ConocoPhillips announced that it had signed a Heads of Agreement (LNG HOA) with The Tokyo Electric Power Company, Incorporated (TEPCO) and Tokyo Gas Co., Ltd. (Tokyo Gas) that would enable Phase II, which involves the export and sale of natural gas, of the Bayu-Undan field development to proceed upon resolution of certain legal, regulatory and fiscal issues. The Timor Sea Treaty (Treaty) was ratified by Timor-Leste´ (formerly East Timor) in December 2002 and by Australia in March 2003 and is subject to certain procedural events before it is fully effective. The Treaty will allow the issuance of new production sharing contracts to the existing contractors in the Bayu-Undan unit, which when combined with expected approval of the Development Plan and the expected enactment of certain Timor-Leste´ legislation will provide the legal, regulatory and fiscal basis necessary to proceed with the gas project. Under the terms of the LNG HOA with TEPCO and Tokyo Gas, TEPCO and Tokyo Gas will purchase 3 million tons per year of liquefied natural gas (LNG) for a period of 17 years, utilizing natural gas from the Bayu-Undan field. Shipments would begin in 2006, from an LNG facility near Darwin, Australia, utilizing ConocoPhillips' Optimized Cascade liquefied natural gas process.

In 2003, ConocoPhillips expects worldwide production of approximately 1.55 million barrels of oil equivalent per day from currently proved reserves. Improvements for the year are expected to come from the United Kingdom, Norway and China. These improvements will be offset by decreases in the U.S. Lower 48 and Canada as a result of the disposition of assets, as well as the impact of the disruptions in Venezuela. In R&M, crude oil throughputs in 2003 are expected to average approximately 2.5 million barrels per day.

Crude oil and natural gas prices are subject to external factors over which the company has no control, such as global economic conditions, political events, demand growth, inventory levels, weather, competing fuels prices and availability of supply. Crude oil prices increased significantly during 2002 due to production restraint by major exporting countries serving to rebalance inventories, supply concerns resulting from Middle East tensions, tropical storms in the U.S. Gulf of Mexico temporarily shutting in oil production and shipping, and the disruptions in Venezuela. Global oil demand is starting to recover on a year-over-year basis, compared with the declines that resulted from the U.S. recession and the events of September 11, 2001. However, the pace of improvement will depend on a continuation of the economic recovery in the United States and globally. Conflicts in oil-producing countries and uncertainties surrounding the global economic recovery could keep prices volatile in 2003. U.S. natural gas prices strengthened considerably at the end of the third quarter and remained strong in the fourth quarter stemming from growing natural gas supply concerns, rising oil prices and an increased demand due to the weather. Supply concerns arose from the decline in domestic gas production and Canadian imports versus 2001, and tropical storms temporarily shutting in production in the Gulf of Mexico.

Refining margins are subject to movements in the price of crude oil and other feedstocks, and the prices of petroleum products, which are subject to market factors over which the company has no control, such as the U.S. and global economies; government regulations; seasonal factors that affect demand, such as the summer driving months; and the levels of refining output and product inventories. Global refining margins remained depressed during much of 2002 due to weak oil demand, relatively high levels of gasoline and distillate inventories and strengthening crude prices, which increased feedstock costs. As a result of tropical storms in the Gulf of Mexico, industry refining crude oil runs were temporarily reduced, which caused product inventory draws in the United States and improved refining margins modestly. Refining and marketing margins can be expected to improve when the U.S. and global economies recover.

CAUTIONARY STATEMENT FOR THE PURPOSES OF THE "SAFE HARBOR" PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995

This annual report includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Forward-looking statements can be identified by the words "expects," "anticipates," "intends," "plans," "projects," "believes," "estimates" and similar expressions.

ConocoPhillips has based the forward-looking statements relating to its operations on its current expectations, estimates and projections about ConocoPhillips and the industries in which it operates in general. ConocoPhillips cautions you that these statements are not guarantees of future performance and involve risks, uncertainties and assumptions that the company cannot predict. In addition, ConocoPhillips has based many of these forward-looking statements on assumptions about future events that may prove to be inaccurate. Accordingly, ConocoPhillips' actual outcomes and results may differ materially from what the company has expressed or forecast in the forward-looking statements. Any differences could result from a variety of factors, including the following:

- fluctuations in crude oil, natural gas and natural gas liquids prices, refining and marketing margins and margins for ConocoPhillips' chemicals business;
- changes in the business, operations, results and prospects of ConocoPhillips;
- the operation and financing of ConocoPhillips' midstream and chemicals joint ventures;
- potential failure to realize fully or within the expected time frame the expected cost savings and synergies from the combination of Conoco and Phillips;
- costs or difficulties related to the integration of the businesses of Conoco and Phillips, as well as the continued integration of businesses recently acquired by each of them;
- potential failure or delays in achieving expected reserve or production levels from existing and future oil and gas development projects due to operating hazards, drilling risks and the inherent uncertainties in predicting oil and gas reserves and oil and gas reservoir performance;
- unsuccessful exploratory drilling activities;
- failure of new products and services to achieve market acceptance;
- unexpected cost increases or technical difficulties in constructing or modifying facilities for exploration and production projects, manufacturing or refining;
- unexpected difficulties in manufacturing or refining ConocoPhillips' refined products, including synthetic crude oil, and chemicals products;

- lack of, or disruptions in, adequate and reliable transportation for ConocoPhillips' crude oil, natural gas and refined products;
- inability to timely obtain or maintain permits, comply with government regulations or make capital expenditures required to maintain compliance;
- potential disruption or interruption of ConocoPhillips' facilities due to accidents, political events or terrorism;
- international monetary conditions and exchange controls;
- liability for remedial actions, including removal and reclamation obligations, under environmental regulations;
- liability resulting from litigation;
- general domestic and international economic and political conditions, including armed hostilities and governmental disputes over territorial boundaries;
- changes in tax and other laws or regulations applicable to ConocoPhillips' business; and
- inability to obtain economical financing for exploration and development projects, construction or modification of facilities and general corporate purposes.

Quantitative and Qualitative Disclosures About Market Risk

Financial Instrument Market Risk

ConocoPhillips and certain of its subsidiaries hold and issue derivative contracts and financial instruments that expose cash flows or earnings to changes in commodity prices, foreign exchange rates or interest rates. The company may use financial and commodity-based derivative contracts to manage the risks produced by changes in the prices of electric power, natural gas, and crude oil and related products, fluctuations in interest rates and foreign currency exchange rates, or to exploit market opportunities.

With the completion of the merger on August 30, 2002, the derivatives policy adopted during the third quarter of 2001 is no longer in effect; however, the ConocoPhillips Board of Directors has approved an "Authority Limitations" document that prohibits the use of highly leveraged derivatives or derivative instruments without sufficient liquidity for comparable valuations without approval from the Chief Executive Officer. The Authority Limitations document also authorizes the Chief Executive Officer to establish the maximum Value at Risk (VaR) limits for the company. Compliance with these limits is monitored daily. The function of the Risk Management Steering Committee, monitoring the use and effectiveness of derivatives, was assumed by the Chief Financial Officer for risks resulting from foreign currency exchange rates and interest rates, and by the Executive Vice President of Commercial, a new position that reports to the Chief Executive Officer, for commodity price risk. ConocoPhillips' Commercial Group manages commercial marketing, optimizes the commodity flows and positions of the company, monitors related risks of the company's upstream and downstream businesses, and selectively takes price risk to add value.

Commodity Price Risk

ConocoPhillips operates in the worldwide crude oil, refined product, natural gas, natural gas liquids, and electric power markets and is exposed to fluctuations in the prices for these commodities. These fluctuations can affect the company's revenues as well as the cost of operating, investing, and financing activities. Generally, the company's policy is to remain exposed to market prices of commodities; however, executive management may elect to use derivative instruments to hedge the price risk of the company's equity crude oil and natural gas production, as well as refinery margins.

The ConocoPhillips' Commercial Group uses futures, forwards, swaps, and options in various markets to optimize the value of the company's supply chain, which may move the company's risk profile away from market average prices to accomplish the following objectives:

- Balance physical systems. In addition to cash settlement prior to contract expiration, exchange traded futures contracts may also be settled by physical delivery of the commodity, providing another source of supply to meet the company's refinery requirements or marketing demand;
- Meet customer needs. Consistent with the company's policy to generally remain exposed to market prices, the company uses swap contracts to convert fixed-price sales contracts, which are often requested by natural gas and refined product consumers, to a floating market price;
- Manage the risk to the company's cash flows from price exposures on specific crude oil, natural gas, refined product and electric power transactions; and
- Enable the company to use the market knowledge gained from these activities to do a limited amount of trading not directly related to the company's physical business. For the 12 months ended December 31, 2002 and 2001, the gains or losses from this activity were not material to the company's cash flows or income from continuing operations.

ConocoPhillips uses a VaR model to estimate the loss in fair value that could potentially result on a single day from the effect of adverse changes in market conditions on the derivative financial instruments and derivative commodity instruments held or issued, including commodity purchase and sales contracts recorded on the balance sheet at December 31, 2002, as derivative instruments in accordance with SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended. Using Monte Carlo simulation, a 95 percent confidence level and a one-day holding period, the VaR for those instruments issued or held for trading purposes at December 31, 2002 and 2001, was $0.7 million at each year-end. The VaR for instruments held for purposes other than trading at December 31, 2002 and 2001, was $2 million and $1.7 million, respectively.

Interest Rate Risk

The following tables provide information about the company's financial instruments that are sensitive to changes in interest rates. The debt tables present principal cash flows and related weighted-average interest rates by expected maturity dates; the derivative table shows the notional quantities on which the cash flows will be calculated by swap termination date. Weighted-average variable rates are based on implied forward rates in the yield curve at the reporting date. The carrying amount of the company's floating-rate debt approximates its fair value. The fair value of the fixed-rate financial instruments is estimated based on quoted market prices.

	Millions of Dollars Except as Indicated					
	Debt				Mandatorily Redeemable Other Minority Interests and Preferred Securities	
Expected Maturity Date	Fixed Rate Maturity	Average Interest Rate	Floating Rate Maturity	Average Interest Rate	Fixed Rate Maturity	Average Interest Rate
Year-End 2002						
2003	**$ 762**	**7.99%**	**$ 706**	**2.60%**	**$ —**	**—%**
2004	**1,362**	**5.91**	**—**	**—**	**—**	**—**
2005	**1,169**	**8.49**	**—**	**—**	**—**	**—**
2006	**1,507**	**5.82**	**1,517**	**4.54**	**—**	**—**
2007	**613**	**4.88**	**—**	**—**	**—**	**—**
Remaining years	**10,740**	**6.95**	**691**	**6.02**	**491**	**7.96**
Total	**$16,153**		**$2,914**		**$ 491**	
Fair value	**$17,930**		**$2,914**		**$ 516**	
Year-End 2001						
2002	$ 43	9.31%	$ —	—%	$ —	—%
2003	255	7.60	—	—	—	—
2004	6	7.02	—	—	—	—
2005	1,155	8.49	—	—	—	—
2006	246	7.61	1,081	7.06	—	—
Remaining years	5,134	7.99	625	6.86	650	8.11
Total	$ 6,839		$1,706		$ 650	
Fair value	$ 7,469		$1,706		$ 662	

	Interest Rate Derivatives at December 31, 2002		
	Floating-to-Fixed		
Expected Maturity Date	Notional	Average Pay Rate	Average Receive Rate
2003	**$500**	**3.41%**	**2.56%**
2004	**—**	**—**	**—**
2005	**—**	**—**	**—**
2006	**166**	**5.85**	**4.76**
2007	**—**	**—**	**—**
Remaining years	**—**	**—**	**—**
Total	**$666**		
Fair value loss position	**$ 22**		

Foreign Currency Risk

ConocoPhillips has foreign currency exchange rate risk resulting from operations in over 40 countries around the world. ConocoPhillips does not comprehensively hedge the exposure to currency rate changes, although the company may choose to selectively hedge exposures to foreign currency rate risk. Examples include firm commitments for capital projects, certain local currency tax payments and dividends, and cash returns from net investments in foreign affiliates to be remitted within the coming year.

At December 31, 2002, ConocoPhillips had the following significant foreign currency derivative contracts:

- approximately $194 million in foreign currency swaps hedging the company's European commercial paper program, with a fair value of $7.1 million;
- approximately $536 million in foreign currency swaps hedging short-term intercompany loans between U.K. subsidiaries and a U.S. subsidiary, with a fair value of $9 million; and
- approximately $24 million in foreign currency swaps hedging the company's firm purchase and sales commitments for gasoline in Germany, with a negative fair value of $4 million.

Although these swaps hedge exposures to fluctuations in exchange rates, the company elected not to utilize hedge accounting as allowed by SFAS No. 133. As a result, the change in the fair value of these foreign currency swaps is recorded directly in earnings. Assuming an adverse hypothetical 10 percent change in the December 31, 2002, exchange rates, the potential foreign currency remeasurement loss in non-cash pretax earning from these swaps, intercompany loans, and commercial paper would be approximately $3 million.

In addition to the intercompany loans discussed above, at December 31, 2002 and 2001, U.S. subsidiaries held long-term sterling-denominated intercompany receivables totaling $152 million and $191 million, respectively, due from a U.K. subsidiary. The U.K. subsidiary also held a dollar-denominated long-term receivable due from a U.S. subsidiary with no balance at December 31, 2002, and a $75 million balance at December 31, 2001. A Norwegian subsidiary held $198 million and $79 million of intercompany U.S. dollar-denominated receivables due from its U.S. parent at December 31, 2002 and 2001, respectively. Also at year-end 2001, a foreign subsidiary with the U.S. dollar as its functional currency owed a $9 million Norwegian kroner-denominated payable to a Norwegian subsidiary. The potential foreign currency remeasurement gains or losses in non-cash pretax earnings from a hypothetical 10 percent change in the year-end 2002 and 2001 exchange rates from these intercompany balances were $35 million and $21 million, respectively.

For additional information about the company's use of derivative instruments, see Note 16 — Derivative Instruments in the Notes to Consolidated Financial Statements.

Selected Financial Data

	Millions of Dollars Except Per Share Amounts				
	2002	2001	2000	1999	1998
Sales and other operating revenues*	**$ 56,748**	24,892	22,155	14,988	12,853
Income from continuing operations*	**714**	1,611	1,848	604	228
Per common share					
Basic	**1.48**	5.50	7.26	2.39	.88
Diluted	**1.47**	5.46	7.21	2.37	.88
Net income (loss)	**(295)**	1,661	1,862	609	237
Per common share					
Basic	**(.61)**	5.67	7.32	2.41	.92
Diluted	**(.61)**	5.63	7.26	2.39	.91
Total assets	**76,836**	35,217	20,509	15,201	14,216
Long-term debt*	**18,917**	8,610	6,622	4,271	4,106
Mandatorily redeemable other minority interests and preferred securities	**491**	650	650	650	650
Cash dividends declared per common share	**1.48**	1.40	1.36	1.36	1.36

**Restated to exclude discontinued operations.*

See Management's Discussion and Analysis of Financial Condition and Results of Operations for a discussion of factors that will enhance an understanding of this data. The following transactions affect the comparability of the amounts included in the table above:

- the merger of Conoco and Phillips in 2002;
- the acquisition of Tosco Corporation in 2001;
- the acquisition of Atlantic Richfield Company's Alaskan operations in 2000; and
- the contribution of a significant portion of the company's midstream and chemicals businesses into joint ventures accounted for using equity-method accounting in 2000.

Selected Quarterly Financial Data

	Millions of Dollars				Per Share of Common Stock			
					Income (Loss) Before Extraordinary Items and Cumulative Effect of Change in Accounting Principle		Net Income (Loss)	
	Sales and Other Operating Revenues*	Income from Continuing Operations Before Income Taxes*	Income (Loss) Before Extraordinary Items and Cumulative Effect of Change in Accounting Principle	Net Income (Loss)	Basic	Diluted	Basic	Diluted
2002								
First	**$ 8,431**	**51**	**(102)**	**(102)**	**(.27)**	**(.27)**	**(.27)**	**(.27)**
Second	**10,414**	**678**	**366**	**351**	**.95**	**.95**	**.91**	**.91**
Third	**14,557**	**312**	**(116)**	**(116)**	**(.24)**	**(.24)**	**(.24)**	**(.24)**
Fourth	**23,346**	**1,123**	**(427)**	**(428)**	**(.63)**	**(.63)**	**(.63)**	**(.63)**
2001								
First	$ 5,160	1,019	488	516	1.91	1.90	2.02	2.01
Second	5,179	1,198	619	619	2.42	2.40	2.42	2.40
Third	5,808	699	374	364	1.35	1.34	1.31	1.30
Fourth	8,745	339	162	162	.42	.42	.42	.42

**Restated to exclude discontinued operations. See Management's Discussion and Analysis and Note 4 — Discontinued Operations in the Notes to Consolidated Financial Statements for additional information. Sales and other operating revenues include excise taxes on petroleum products sales.*

Quarterly Common Stock Prices and Cash Dividends Per Share

Phillips Petroleum Company's (predecessor to ConocoPhillips) stock was traded primarily on the New York, Pacific and Toronto stock exchanges. On August 30, 2002, it ceased trading.

Phillips Petroleum Company (predecessor to ConocoPhillips)	Stock Price		
	High	Low	Dividends
2002			
First	**$63.80**	**55.30**	**.36**
Second	**64.10**	**54.53**	**.36**
Third (through August 30)	**59.21**	**44.75**	**N/A**
2001			
First	$59.00	51.70	.34
Second	68.00	52.78	.34
Third	59.86	50.00	.36
Fourth	60.95	50.66	.36

ConocoPhillips' common stock began trading on September 3, 2002, the first trading day after the effective date of the merger.

	Stock Price		
	High	Low	Dividends
2002			
Third (from September 3)	**$53.20**	**45.87**	**.36**
Fourth	**50.75**	**44.03**	**.40**
Closing Stock Price at December 31, 2002			**$48.39**
Number of Stockholders of Record at February 28, 2003			60,666

ConocoPhillips' common stock is traded on the New York Stock Exchange.

Report of Management

Management prepared, and is responsible for, the consolidated financial statements and the other information appearing in this annual report. The consolidated financial statements present fairly the company's financial position, results of operations and cash flows in conformity with accounting principles generally accepted in the United States. In preparing its consolidated financial statements, the company includes amounts that are based on estimates and judgments that management believes are reasonable under the circumstances.

The company maintains internal controls designed to provide reasonable assurance that the company's assets are protected from unauthorized use and that all transactions are executed in accordance with established authorizations and recorded properly. The internal controls are supported by written policies and guidelines and are complemented by a staff of internal auditors. Management believes that the internal controls in place at December 31, 2002, provide reasonable assurance that the books and records reflect the transactions of the company and there has been compliance with its policies and procedures.

The company's financial statements have been audited by Ernst & Young LLP, independent auditors selected by the Audit and Compliance Committee of the Board of Directors. Management has made available to Ernst & Young LLP all of the company's financial records and related data, as well as the minutes of stockholders' and directors' meetings.

Archie W. Dunham
Chairman of the Board

J.J. Mulva
President and
Chief Executive Officer

John A. Carrig
Executive Vice President, Finance,
and Chief Financial Officer

March 24, 2003

Report of Independent Auditors

The Board of Directors and Stockholders
ConocoPhillips

We have audited the accompanying consolidated balance sheets of ConocoPhillips as of December 31, 2002 and 2001, and the related consolidated statements of operations, changes in common stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2002. These financial statements are the responsibility of the company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of ConocoPhillips at December 31, 2002 and 2001, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2002, in conformity with accounting principles generally accepted in the United States.

As discussed in Note 2 to the consolidated financial statements, in 2001 ConocoPhillips changed its method of accounting for the costs of major maintenance turnarounds.

Ernst + Young LLP

Houston, Texas
March 24, 2003

Years Ended December 31	Millions of Dollars		
	2002	2001**	2000**
Revenues			
Sales and other operating revenues*	**$56,748**	24,892	22,155
Equity in earnings of affiliates	**261**	41	114
Other income	**215**	111	270
Total Revenues	**57,224**	25,044	22,539
Costs and Expenses			
Purchased crude oil and products	**37,823**	13,708	11,794
Production and operating expenses	**4,988**	2,643	2,136
Selling, general and administrative expenses	**1,660**	613	571
Exploration expenses	**592**	306	298
Depreciation, depletion and amortization	**2,223**	1,344	1,169
Impairments	**177**	26	100
Taxes other than income taxes*	**6,937**	2,740	2,242
Accretion on discounted liabilities	**22**	7	—
Interest and debt expense	**566**	338	369
Foreign currency transaction losses	**24**	11	58
Preferred dividend requirements of capital trusts and minority interests	**48**	53	54
Total Costs and Expenses	**55,060**	21,789	18,791
Income from continuing operations before income taxes	**2,164**	3,255	3,748
Provision for income taxes	**1,450**	1,644	1,900
Income From Continuing Operations	**714**	1,611	1,848
Income (loss) from discontinued operations (net of income taxes (benefit) of $(394), $15, and $7 for 2002, 2001 and 2000, respectively)	**(993)**	32	14
Income (Loss) Before Extraordinary Items and Cumulative Effect of Change in Accounting Principle	**(279)**	1,643	1,862
Extraordinary items	**(16)**	(10)	—
Cumulative effect of change in accounting principle	**—**	28	—
Net Income (Loss)	**$ (295)**	1,661	1,862
Net Income (Loss) Per Share of Common Stock			
Basic			
Continuing operations	**$ 1.48**	5.50	7.26
Discontinued operations	**(2.06)**	.11	.06
Before extraordinary items and cumulative effect of change in accounting principle	**(.58)**	5.61	7.32
Extraordinary items	**(.03)**	(.04)	—
Cumulative effect of change in accounting principle	**—**	.10	—
Net Income (Loss)	**$ (.61)**	5.67	7.32
Diluted			
Continuing operations	**$ 1.47**	5.46	7.21
Discontinued operations	**(2.05)**	.11	.05
Before extraordinary items and cumulative effect of change in accounting principle	**(.58)**	5.57	7.26
Extraordinary items	**(.03)**	(.03)	—
Cumulative effect of change in accounting principle	**—**	.09	—
Net Income (Loss)	**$ (.61)**	5.63	7.26
Average Common Shares Outstanding (in thousands)			
Basic	**482,082**	292,964	254,490
Diluted	**485,505**	295,016	256,326
**Includes excise taxes on petroleum products sales:*	***$ 6,236***	*2,178*	*1,781*

***Restated for discontinued operations.*
See Notes to Consolidated Financial Statements.

Consolidated Balance Sheet

At December 31	Millions of Dollars	
	2002	2001*
Assets		
Cash and cash equivalents	**$ 307**	142
Accounts and notes receivable (net of allowance of $48 million in 2002 and $33 million in 2001)	**2,904**	1,124
Accounts and notes receivable — related parties	**1,476**	105
Inventories	**3,845**	2,452
Prepaid expenses and other current assets	**766**	293
Assets of discontinued operations held for sale	**1,605**	2,382
Total Current Assets	**10,903**	6,498
Investments and long-term receivables	**6,821**	3,309
Net properties, plants and equipment	**43,030**	22,133
Goodwill	**14,444**	2,281
Intangibles	**1,119**	861
Other assets	**519**	135
Total	**$ 76,836**	35,217
Liabilities		
Accounts payable	**$ 5,949**	2,531
Accounts payable — related parties	**303**	91
Notes payable and long-term debt due within one year	**849**	44
Accrued income and other taxes	**1,991**	897
Other accruals	**3,075**	720
Liabilities of discontinued operations held for sale	**649**	538
Total Current Liabilities	**12,816**	4,821
Long-term debt	**18,917**	8,610
Accrued dismantlement, removal and environmental costs	**1,666**	1,059
Deferred income taxes	**8,361**	4,015
Employee benefit obligations	**2,755**	948
Other liabilities and deferred credits	**1,803**	769
Total Liabilities	**46,318**	20,222
Company-Obligated Mandatorily Redeemable Preferred Securities of Phillips 66 Capital Trusts I and II	**350**	650
Other Minority Interests	**651**	5
Common Stockholders' Equity		
Common stock (2002 — 2,500,000,000 shares authorized at $.01 par value; 2001 — 1,000,000,000 shares authorized at $1.25 par value)		
Issued (2002 — 704,354,839 shares; 2001 — 430,439,743 shares)		
Par value	**7**	538
Capital in excess of par	**25,178**	9,069
Treasury stock (at cost: 2001 — 20,725,114 shares)	**—**	(1,038)
Compensation and Benefits Trust (CBT) (at cost: 2002 — 26,785,094 shares; 2001 — 27,556,573 shares)	**(907)**	(934)
Accumulated other comprehensive loss	**(164)**	(255)
Unearned employee compensation — Long-Term Stock Savings Plan (LTSSP)	**(218)**	(237)
Retained earnings	**5,621**	7,197
Total Common Stockholders' Equity	**29,517**	14,340
Total	**$ 76,836**	35,217

**Restated for discontinued operations.*
See Notes to Consolidated Financial Statements.

Consolidated Statement of Cash Flows

Years Ended December 31	Millions of Dollars		
	2002	2001*	2000*
Cash Flows From Operating Activities			
Income from continuing operations	**$ 714**	1,611	1,848
Adjustments to reconcile income from continuing operations to net cash provided by continuing operations			
Non-working capital adjustments			
Depreciation, depletion and amortization	**2,223**	1,344	1,169
Impairments	**177**	26	100
Dry hole costs and leasehold impairment	**307**	99	130
Accretion on discounted liabilities	**22**	7	—
Acquired in-process research and development	**246**	—	—
Deferred taxes	**142**	513	412
Other	**(46)**	131	(210)
Working capital adjustments**			
Increase (decrease) in aggregate balance of accounts receivable sold	**(22)**	(174)	317
Decrease (increase) in other accounts and notes receivable	**(401)**	1,357	(710)
Decrease (increase) in inventories	**200**	(289)	(12)
Decrease (increase) in prepaid expenses and other current assets	**(37)**	50	84
Increase (decrease) in accounts payable	**788**	(1,004)	417
Increase (decrease) in taxes and other accruals	**454**	(142)	439
Net cash provided by continuing operations	**4,767**	3,529	3,984
Net cash provided by discontinued operations	**202**	33	30
Net Cash Provided by Operating Activities	**4,969**	3,562	4,014
Cash Flows From Investing Activities			
Acquisitions, net of cash acquired	**1,180**	80	(6,443)
Capital expenditures and investments, including dry hole costs	**(4,388)**	(3,016)	(2,017)
Proceeds from contributing assets to joint ventures	**—**	—	2,061
Proceeds from asset dispositions	**815**	262	850
Long-term advances to affiliates and other investments	**(92)**	(28)	(208)
Net cash used in continuing operations	**(2,485)**	(2,702)	(5,757)
Net cash used in discontinued operations	**(99)**	(68)	(5)
Net Cash Used in Investing Activities	**(2,584)**	(2,770)	(5,762)
Cash Flows From Financing Activities			
Issuance of debt	**3,502**	566	2,552
Repayment of debt	**(4,592)**	(945)	(360)
Redemption of preferred stock of subsidiary	**(300)**	—	—
Issuance of company common stock	**44**	51	31
Dividends paid on common stock	**(684)**	(403)	(346)
Other	**(190)**	(68)	(118)
Net cash provided by (used in) continuing operations	**(2,220)**	(799)	1,759
Net Cash Provided by (Used in) Financing Activities	**(2,220)**	(799)	1,759
Net Change in Cash and Cash Equivalents	**165**	(7)	11
Cash and cash equivalents at beginning of year	**142**	149	138
Cash and Cash Equivalents at End of Year	**$ 307**	142	149

**Restated for discontinued operations.*
***Net of acquisition and disposition of businesses.*
See Notes to Consolidated Financial Statements.

Consolidated Statement of Changes in Common Stockholders' Equity

	Shares of Common Stock			Millions of Dollars							
				Common Stock				Accumulated Other Comprehensive Loss	Unearned Employee Compensation — LTSSP	Retained Earnings	Total
	Issued	Held in Treasury	Held in CBT	Par Value	Capital in Excess of Par	Treasury Stock	CBT				
December 31, 1999	306,380,511	24,409,545	28,358,258	$ 383	2,098	(1,217)	(961)	(31)	(286)	4,563	4,549
Net income										1,862	1,862
Other comprehensive income											
Foreign currency translation								(53)			(53)
Unrealized loss on securities								(1)			(1)
Equity affiliates:											
Foreign currency translation								(15)			(15)
Comprehensive income											1,793
Cash dividends paid on common stock										(346)	(346)
Distributed under incentive compensation and other benefit plans		(1,267,540)	(508,828)		55	61	18			(65)	69
Recognition of LTSSP unearned compensation									23		23
Tax benefit of dividends on unallocated LTSSP shares										5	5
December 31, 2000	306,380,511	23,142,005	27,849,430	383	2,153	(1,156)	(943)	(100)	(263)	6,019	6,093
Net income										1,661	1,661
Other comprehensive income											
Minimum pension liability adjustment								(143)			(143)
Foreign currency translation								(14)			(14)
Unrealized loss on securities								(2)			(2)
Hedging activities								(4)			(4)
Equity affiliates:											
Foreign currency translation								(3)			(3)
Derivatives related								11			11
Comprehensive income											1,506
Cash dividends paid on common stock										(403)	(403)
Tosco acquisition	124,059,232			155	6,883						7,038
Distributed under incentive compensation and other benefit plans		(2,416,891)	(292,857)		33	118	9			(84)	76
Recognition of LTSSP unearned compensation									26		26
Tax benefit of dividends on unallocated LTSSP shares										4	4
December 31, 2001	430,439,743	20,725,114	27,556,573	538	9,069	(1,038)	(934)	(255)	(237)	7,197	14,340
Net loss										**(295)**	**(295)**
Other comprehensive income											
Minimum pension liability adjustment								**(93)**			**(93)**
Foreign currency translation								**182**			**182**
Unrealized loss on securities								**(3)**			**(3)**
Hedging activities								**(1)**			**(1)**
Equity affiliates:											
Foreign currency translation								**40**			**40**
Derivatives related								**(34)**			**(34)**
Comprehensive loss											**(204)**
Cash dividends paid on common stock										**(684)**	**(684)**
ConocoPhillips merger	**273,471,505**	**(19,852,674)**		**(531)**	**16,056**	**999**				**(562)**	**15,962**
Distributed under incentive compensation and other benefit plans	**443,591**	**(872,440)**	**(771,479)**		**53**	**39**	**27**			**(39)**	**80**
Recognition of LTSSP unearned compensation									**19**		**19**
Tax benefit of dividends on unallocated LTSSP shares										**4**	**4**
December 31, 2002	**704,354,839**	**—**	**26,785,094**	**$ 7**	**25,178**	**—**	**(907)**	**(164)**	**(218)**	**5,621**	**29,517**

See Notes to Consolidated Financial Statements.

Notes to Consolidated Financial Statements

Note 1 — Accounting Policies

- **Consolidation Principles and Investments —** Majority-owned, controlled subsidiaries are consolidated. The equity method is used to account for investments in affiliates in which the company exerts significant influence, generally having a 20 to 50 percent ownership interest. The company also uses the equity method for its 50.1 percent and 57.1 percent non-controlling interests in Petrozuata C.A. and Hamaca Holding LLC, respectively, located in Venezuela because the minority shareholders have substantive participating rights, under which all substantive operating decisions (e.g., annual budgets, major financings, selection of senior operating management, etc.) require joint approvals. Undivided interests in oil and gas joint ventures, pipelines, natural gas plants, certain transportation assets and Canadian Syncrude mining operations are consolidated on a proportionate basis. Other securities and investments, excluding marketable securities, are generally carried at cost.

- **Revenue Recognition —** Revenues associated with sales of crude oil, natural gas, natural gas liquids, petroleum and chemical products, and all other items are recorded when title passes to the customer. Revenues include the sales portion of contracts involving purchases and sales necessary to reposition supply to address location or quality or grade requirements (e.g., when the company repositions crude by entering into a contract with a counterparty to sell crude in one location and purchase it in a different location) and sales related to purchase for resale activity. Revenues from the production of natural gas properties in which the company has an interest with other producers are recognized based on the actual volumes sold by the company during the period. Any differences between volumes sold and entitlement volumes, based on the company's net working interest, which are deemed non-recoverable through remaining production, are recognized as accounts receivable or accounts payable, as appropriate. Cumulative differences between volumes sold and entitlement volumes are not significant. Revenues associated with royalty fees from licensed technology are recorded based either upon volumes produced by the licensee or upon the successful completion of all substantive performance requirements related to the installation of licensed technology.

- **Reclassification —** Certain amounts in the 2001 and 2000 financial statements have been reclassified to conform with the 2002 presentation.

- **Use of Estimates —** The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and the disclosures of contingent assets and liabilities. Actual results could differ from the estimates and assumptions used.

- **Cash Equivalents —** Cash equivalents are highly liquid short-term investments that are readily convertible to known amounts of cash and have original maturities within three months from their date of purchase. They are carried at cost plus accrued interest, which approximates fair value.

- **Inventories —** The company has several valuation methods for its various types of inventories and consistently uses the following methods for each type of inventory. Crude oil, petroleum products, and Canadian Syncrude inventories are valued at the lower of cost or market in the aggregate, primarily on the last-in, first-out (LIFO) basis. Any necessary lower-of-cost-or-market write-downs are recorded as permanent adjustments to the LIFO cost basis. LIFO is used to better match current inventory costs with current revenues and to meet tax-conformity requirements. Materials, supplies and other miscellaneous inventories are valued using the weighted-average-cost method, consistent with general industry practice. Merchandise inventories at the company's retail marketing outlets are valued using the first-in, first-out (FIFO) retail method, consistent with general industry practice.

- **Derivative Instruments —** All derivative instruments are recorded on the balance sheet at fair value in either accounts and notes receivable, other assets, accounts payable, or other liabilities and deferred credits. Recognition of the gain or loss that results from recording and adjusting a derivative to fair value depends on the purpose for issuing or holding the derivative. Gains and losses from derivatives that are not used as hedges are recognized immediately in earnings. For derivative instruments that are designated and qualify as a fair value hedge, the gains or losses from adjusting the derivative to its fair value will be immediately recognized in earnings and, to the extent the hedge is effective, offset the concurrent recognition of changes in the fair value of the hedged item. Gains or losses from derivative instruments that are designated and qualify as a cash flow hedge will be recorded on the balance sheet in accumulated other comprehensive income/(loss) until the hedged transaction is recognized in earnings; however, to the extent the change in the value of the derivative exceeds the change in the anticipated cash flows of the hedged transaction, the excess gains or losses will be recognized immediately in earnings.

  In the consolidated statement of operations, gains and losses from derivatives that are not directly related to the company's movement of its products are recorded in other income. Gains and losses from derivatives used for other purposes are recorded in either sales and other operating revenues, other income, or purchased crude oil and products, depending on the purpose for issuing or holding the derivative.

- **Oil and Gas Exploration and Development —** Oil and gas exploration and development costs are accounted for using the successful efforts method of accounting.

  Property Acquisition Costs — Oil and gas leasehold acquisition costs are capitalized. Leasehold impairment is recognized based on exploratory experience and management's judgment. Upon discovery of commercial reserves, leasehold costs are transferred to proved properties.

  Exploratory Costs — Geological and geophysical costs and the costs of carrying and retaining undeveloped properties are expensed as incurred. Exploratory well costs are capitalized pending further evaluation of whether economically recoverable reserves have been found. If economically recoverable reserves are not found, exploratory well costs are expensed as dry holes. All exploratory wells are evaluated for economic viability within one year of well completion. Exploratory wells that discover potentially economic reserves that are in areas where a major capital expenditure would be required before production could begin, and where the economic viability of that major capital expenditure depends upon the successful completion of further exploratory work in the area, remain capitalized as long as the additional exploratory work is under way or firmly planned.

Development Costs — Costs incurred to drill and equip development wells, including unsuccessful development wells, are capitalized.

Depletion and Amortization — Leasehold costs of producing properties are depleted using the unit-of-production method based on estimated proved oil and gas reserves. Amortization of intangible development costs is based on the unit-of-production method using estimated proved developed oil and gas reserves.

- **Syncrude Mining Operations —** Capitalized costs, including support facilities, include the cost of the acquisition and other capital costs incurred. Capital costs are depreciated using the unit-of-production method based on the applicable portion of proven reserves associated with each mine location and its facilities.

- **Intangible Assets Other Than Goodwill —** Intangible assets that have finite useful lives are amortized by the straight-line method over their useful lives. Intangible assets that have indefinite useful lives are not amortized but are tested at least annually for impairment. The company evaluates the remaining useful lives of intangible assets not being amortized each reporting period to determine whether events and circumstances continue to support indefinite useful lives. Intangible assets are considered impaired if the fair value of the intangible asset is lower than cost. The fair value of intangible assets is determined based on quoted market prices in active markets, if available. If quoted market prices are not available, fair value of intangible assets is determined based upon the present values of expected future cash flows using discount rates commensurate with the risks involved in the asset, or upon estimated replacement cost, if expected future cash flows from the intangible asset are not determinable.

- **Goodwill —** Goodwill is not amortized but is tested at least annually for impairment. If the fair value of a reporting unit is less than the recorded book value of the reporting unit's assets (including goodwill), less liabilities, then a hypothetical purchase price allocation is performed on the reporting unit's assets and liabilities using the fair value of the reporting unit as the purchase price in the calculation. If the amount of goodwill resulting from this hypothetical purchase price allocation is less than the recorded amount of goodwill, the recorded goodwill is written down to the new amount. Reporting units for purposes of goodwill impairment calculations are one level below or at the company's operating segment level. Because quoted market prices are not available for the company's reporting units, the fair value of the reporting units is determined based upon consideration of several factors, including observed market multiples of operating cash flows and net income, the depreciated replacement cost of tangible equipment, and/or the present values of expected future cash flows using discount rates commensurate with the risks involved in the assets.

- **Depreciation and Amortization —** Depreciation and amortization of properties, plants and equipment on producing oil and gas properties, certain pipeline assets (those which are expected to have a declining utilization pattern), and on Syncrude mining operations are determined by the unit-of-production method. Depreciation and amortization of all other properties, plants and equipment are determined by either the individual-unit-straight-line method or the group-straight-line method (for those individual units that are highly integrated with other units).

- **Impairment of Properties, Plants and Equipment —** Properties, plants and equipment used in operations are assessed for impairment whenever changes in facts and circumstances indicate a possible significant deterioration in the future cash flows expected to be generated by an asset group. If, upon review, the sum of the undiscounted pretax cash flows is less than the carrying value of the asset group, the carrying value is written down to estimated fair value through additional amortization or depreciation provisions in the periods in which the determination of impairment is made. Individual assets are grouped for impairment purposes at the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets — generally on a field-by-field basis for exploration and production assets, at an entire complex level for downstream assets or at a site level for retail stores. The fair value of impaired assets is determined based on quoted market prices in active markets, if available, or upon the present values of expected future cash flows using discount rates commensurate with the risks involved in the asset group. Long-lived assets committed by management for disposal within one year are accounted for at the lower of amortized cost or fair value, less cost to sell.

The expected future cash flows used for impairment reviews and related fair value calculations are based on estimated future production volumes, prices and costs, considering all available evidence at the date of review. If the future production price risk has been hedged, the hedged price is used in the calculations for the period and quantities hedged. The impairment review includes cash flows from proved developed and undeveloped reserves, including any development expenditures necessary to achieve that production. The price and cost outlook assumptions used in impairment reviews differ from the assumptions used in the Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserve Quantities. In that disclosure, Statement of Financial Accounting Standards (SFAS) No. 69, "Disclosures about Oil and Gas Producing Activities," requires the use of prices and costs at the balance sheet date, with no projection of future changes in those assumptions.

- **Maintenance and Repairs —** The costs of maintenance and repairs, which are not significant improvements, are expensed when incurred. Effective January 1, 2001, turnaround costs of major producing units are expensed as incurred. Prior to 2001, the estimated turnaround costs of major producing units were accrued in other liabilities over the estimated interval between turnarounds. See Note 2 — Extraordinary Items and Accounting Change for further discussion of this change in accounting method.

- **Shipping and Handling Costs —** The company's Exploration and Production segment includes shipping and handling costs in production and operating expenses, while the Refining and Marketing segment records shipping and handling costs in purchased crude oil and products.

- **Advertising Costs —** Production costs of media advertising are deferred until the first public showing of the advertisement. Advances to secure advertising slots at specific sports, racing or other events are deferred until the event occurs. All other advertising costs are expensed as incurred, unless the cost has benefits which clearly extend beyond the interim period in which the expenditure is made, in which case the advertising cost is deferred and amortized ratably over the interim periods which clearly benefit from the expenditure. By the end of the fiscal year, all such interim deferred advertising costs are fully amortized to expense.

- **Property Dispositions —** When complete units of depreciable property are retired or sold, the asset cost and related accumulated depreciation are eliminated, with any gain or loss reflected in income. When less than complete units of depreciable property are disposed of or retired, the difference between asset cost and salvage value is charged or credited to accumulated depreciation.

- **Dismantlement, Removal and Environmental Costs —** Through December 31, 2002, the estimated undiscounted costs, net of salvage values, of dismantling and removing major oil and gas production and transportation facilities, including necessary site restoration, were accrued using either the unit-of-production or the straight-line method, which was used for certain regional production transportation assets that are expected to have a straight-line utilization pattern. Effective January 1, 2003, the company adopted SFAS No. 143, "Accounting for Asset Retirement Obligations." See Note 27 — New Accounting Standards.

  Environmental expenditures are expensed or capitalized, depending upon their future economic benefit. Expenditures that relate to an existing condition caused by past operations, and that do not have future economic benefit, are expensed. Liabilities for these expenditures are recorded on an undiscounted basis (unless acquired in a purchase business acquisition) when environmental assessments or cleanups are probable and the costs can be reasonably estimated. Recoveries of environmental remediation costs from other parties are recorded as assets when their receipt is probable.

- **Stock Compensation —** Through December 31, 2002, the company accounted for stock options using the intrinsic value method as prescribed by the Accounting Principles Board (APB) Opinion No. 25, "Accounting for Stock Issued to Employees," and related interpretations. Pro forma information regarding changes in net income and earnings per share data (as if the accounting prescribed by SFAS No. 123, "Accounting for Stock-Based Compensation," had been applied) is presented in Note 20 — Employee Benefit Plans. Effective January 1, 2003, the company voluntarily adopted SFAS No. 123 prospectively. See Note 20 — Employee Benefit Plans.

- **Foreign Currency Translation —** Adjustments resulting from the process of translating foreign functional currency financial statements into U.S. dollars are included in accumulated other comprehensive loss in common stockholders' equity. Foreign currency transaction gains and losses are included in current earnings. Most of the company's foreign operations use their local currency as the functional currency.

- **Income Taxes —** Deferred income taxes are computed using the liability method and are provided on all temporary differences between the financial-reporting basis and the tax basis of the company's assets and liabilities, except for deferred taxes on income considered to be permanently reinvested in certain foreign subsidiaries and foreign corporate joint ventures. Allowable tax credits are applied currently as reductions of the provision for income taxes.

- **Net Income Per Share of Common Stock —** Basic income per share of common stock is calculated based upon the daily weighted-average number of common shares outstanding during the year, including shares held by the Long-Term Stock Savings Plan (LTSSP). Diluted income per share of common stock includes the above, plus "in-the-money" stock options issued under company compensation plans. Treasury stock and shares held by the Compensation and Benefits Trust (CBT) are excluded from the daily weighted-average number of common shares outstanding in both calculations.

- **Capitalized Interest —** Interest from external borrowings is capitalized on major projects with an expected construction period of one year or longer. Capitalized interest is added to the cost of the underlying asset and is amortized over the useful lives of the assets in the same manner as the underlying assets.

Note 2 — Extraordinary Items and Accounting Change

During 2002, the company incurred extraordinary losses totaling $16 million after-tax ($24 million before-tax) on the following items:

- the call premium on the early retirement of the company's $250 million 8.86% notes due May 15, 2022;
- the redemption of the company's outstanding 8.24% Junior Subordinated Deferrable Interest Debentures due 2036, which triggered the redemption of the $300 million of 8.24% Trust Originated Preferred Securities of Phillips 66 Capital Trust I; and
- the call premium on the early retirement of the company's $171 million 7.443% notes due 2004.

In 2001, ConocoPhillips incurred an extraordinary loss of $10 million after-tax ($14 million before-tax) attributable to the call premium on the early retirement of its $300 million 9.18% notes due September 15, 2021.

Effective January 1, 2001, the company changed its method of accounting for the costs of major maintenance turnarounds from the accrue-in-advance method to the expense-as-incurred method to reflect the impact of a turnaround in the period that it occurs. The new method is preferable because it results in the recognition of costs at the time obligations are incurred. The cumulative effect of this accounting change increased net income in 2001 by $28 million (after reduction for income taxes of $15 million).

The pro forma effects of retroactive application of the change in accounting method are presented below:

	Millions of Dollars Except Per Share Amounts	
	2001	2000
Income before extraordinary items	$1,643	1,851
Earnings per share		
Basic	5.61	7.27
Diluted	5.57	7.22
Net income	$1,633	1,851
Earnings per share		
Basic	5.57	7.27
Diluted	5.54	7.22

Note 3 — Merger of Conoco and Phillips

On August 30, 2002, Conoco and Phillips combined their businesses by merging with separate acquisition subsidiaries of ConocoPhillips (the merger). As a result, each company became a wholly owned subsidiary of ConocoPhillips. For accounting purposes, Phillips was treated as the acquirer of Conoco, and ConocoPhillips was treated as the successor of Phillips.

Immediately after the closing of the merger, former Phillips stockholders held approximately 56 percent of the outstanding shares of ConocoPhillips common stock, while former Conoco stockholders held approximately 44 percent. ConocoPhillips common stock, listed on the New York Stock Exchange under the symbol "COP," began trading on September 3, 2002.

The primary reasons for the merger and the principal factors that contributed to an accounting treatment that resulted in the recognition of goodwill were:

- the combination of Conoco and Phillips would create a stronger, major, integrated oil company with the benefits of increased size and scale, improving the stability of the combined business' earnings in varying economic and market climates;
- ConocoPhillips would emerge with a global presence in both upstream and downstream petroleum businesses, increasing its overall international presence to over 40 countries while maintaining a strong domestic base; and
- combining the two companies' operations would provide significant synergies and related cost savings, and improve future access to capital.

The $16 billion purchase price attributed to Conoco for accounting purposes was based on an exchange of Conoco shares for ConocoPhillips common shares. ConocoPhillips issued approximately 293 million shares of common stock and approximately 23.3 million of employee stock options in exchange for 627 million shares of Conoco common stock and 49.8 million Conoco stock options. The common stock was valued at $53.15 per share, which was Phillips' average common stock price over the two-day trading period immediately before and after the November 18, 2001, public announcement of the transaction. The Conoco stock options, the fair value of which was determined using the Black-Scholes option-pricing model, were exchanged for ConocoPhillips stock options valued at $384 million. Transaction-related costs, included in the purchase price, were $82 million.

The preliminary allocation of the purchase price to specific assets and liabilities was based, in part, upon an outside appraisal of the fair value of Conoco's assets. Over the next few months ConocoPhillips expects to receive the final outside appraisal of the long-lived assets and conclude the fair value determination of all other Conoco assets and liabilities. Subsequent to completion of the final allocation of the purchase price and the determination of the ultimate asset and liability tax bases, the deferred tax liabilities will also be finalized. The following table summarizes, based on the year-end preliminary purchase price allocation, the fair values of the assets acquired and liabilities assumed as of August 30, 2002:

	Millions of Dollars
Cash and cash equivalents	$ 1,250
Accounts and notes receivable	2,821
Inventories	1,603
Prepaid expenses and other current assets	324
Investments and long-term receivables	3,074
Properties, plants and equipment (including $300 million of land)	19,269
Goodwill	12,079
Intangibles	661
In-process research and development	246
Other assets	312
Total assets	$41,639
Accounts payable	$2,879
Notes payable and long-term debt due within one year	3,101
Accrued income and other taxes	1,320
Other accruals	1,543
Long-term debt	8,930
Accrued dismantlement, removal and environmental costs	332
Deferred income taxes	4,073
Employee benefit obligations	1,648
Other liabilities and deferred credits	1,109
Minority interests	648
Common stockholders' equity	16,056
Total liabilities and equity	$41,639

The allocation of the purchase price, as reflected above, has not been adjusted for the U.S. Federal Trade Commission (FTC)-mandated dispositions described in Note 4 — Discontinued Operations. Goodwill, land and certain identifiable intangible assets recorded in the acquisition are not subject to amortization, but the goodwill and intangible assets will be tested periodically for impairment as required by SFAS No. 142, "Goodwill and Other Intangible Assets."

Of the $661 million allocated to intangible assets, $545 million is assigned to marketing tradenames which are not subject to amortization. Of the remaining value assigned to intangible assets, $66 million assigned to refining technology will be amortized over 11 years and $50 million was allocated to other intangible assets with a weighted-average amortization period of 11 years.

ConocoPhillips has not yet determined the assignment of Conoco goodwill to specific reporting units. Currently, Conoco goodwill is being reported as part of the Corporate and Other reporting segment. Of the $12,079 million of goodwill, $4,302 million is attributable to the gross-up required under purchase accounting for deferred taxes. This and the remaining "true" goodwill, or $7,777 million, will ultimately be assigned to reporting units based on the benefits received by the units from the synergies and strategic advantages of the merger. None of the goodwill is deductible for tax purposes.

The purchase price allocation included $246 million of in-process research and development costs related to Conoco's natural gas-to-liquids and other technologies. In accordance with Financial Accounting Standards Board (FASB) Interpretation No. 4, "Applicability of FASB Statement No. 2 to Business Combinations Accounted for by the Purchase Method," the value assigned to the research and development activities was charged to production and operating expenses in the Emerging Businesses segment at the date of the consummation of the merger, as these research and development costs had no alternative future use.

Merger-related items that reduced ConocoPhillips' 2002 income from continuing operations were:

	Millions of Dollars	
	Before-Tax	After-Tax
Write-off of acquired in-process research and development costs	$246	246
Restructuring charges (see Note 5)	422	253
Incremental seismic contract costs	35	22
Transition costs	55	36
Total	$758	557

In total, these items reduced 2002 income from continuing operations by $557 million ($1.15 per share on a diluted basis).

The following pro forma summary presents information as if the merger had occurred at the beginning of each period presented, and includes the $557 million effect of the merger-related items mentioned above.

	Millions of Dollars Except Per Share Amounts	
	2002	2001
Revenues	**$81,433**	79,554
Income from continuing operations	**918**	3,635
Net income (loss)	**(70)**	4,072
Income from continuing operations per share of common stock		
Basic	**1.36**	5.39
Diluted	**1.34**	5.32
Net income (loss) per share of common stock		
Basic	**(.10)**	6.04
Diluted	**(.10)**	5.97

During 2001, both Phillips and Conoco entered into other significant transactions that are not reflected in the companies' historical income statements for the full year 2001. The pro forma results have been prepared as if the Phillips' September 14, 2001, acquisition of Tosco Corporation (Tosco) (see Note 6 — Acquisition of Tosco Corporation) and Conoco's July 16, 2001, $4.6 billion acquisition of Gulf Canada Resources Limited occurred on January 1, 2001. Gulf Canada Resources Limited was a Canadian-based independent exploration and production company with primary operations in Western Canada, Indonesia, the Netherlands and Ecuador.

The pro forma results reflect the following:

- recognition of depreciation and amortization based on the preliminary allocated purchase price of the properties, plants and equipment acquired;
- adjustment of interest for the amortization of the fair-value adjustment to debt;
- cessation of the amortization of deferred gains not recognizable in the purchase price allocation;
- accretion of discount on environmental accruals recorded at net present value; and
- various other adjustments to conform Conoco's accounting policies to ConocoPhillips'.

The pro forma adjustments use estimates and assumptions based on currently available information. Management believes that the estimates and assumptions are reasonable, and that the significant effects of the transactions are properly reflected.

The pro forma information does not reflect any anticipated synergies that might be achieved from combining the operations. The pro forma information is not intended to reflect the actual results that would have occurred had the companies been combined during the periods presented. This pro forma information is not intended to be indicative of the results of operations that may be achieved by ConocoPhillips in the future.

Note 4 — Discontinued Operations

During 2002, the company disposed of, or had committed to a plan to dispose of, U.S. retail and wholesale marketing assets, U.S. refining and related assets, and exploration and production assets in the Netherlands. Certain of these planned dispositions were mandated by the FTC as a condition of the merger. For reporting purposes, these operations are classified as discontinued operations, and in Note 26 — Segment Disclosures and Related Information, these operations are included in Corporate and Other.

Revenues and income (loss) from discontinued operations were as follows:

	Millions of Dollars		
	2002	2001	2000
Sales and other operating revenues from discontinued operations	**$ 7,406**	2,670	786
Income (loss) from discontinued operations before-tax	**$(1,387)**	47	21
Income tax expense (benefit)	**(394)**	15	7
Income (loss) from discontinued operations	**$ (993)**	32	14

Major classes of assets and liabilities of discontinued operations held for sale were as follows:

	Millions of Dollars	
	2002	2001
Assets		
Inventories	**$ 211**	166
Other current assets	**136**	81
Net properties, plants and equipment	**1,178**	1,663
Intangibles	**23**	452
Other assets	**57**	20
Assets of discontinued operations	**$1,605**	2,382
Liabilities		
Accounts payable and other current liabilities	**$ 331**	259
Long-term debt	**34**	35
Accrued dismantlement, removal and environmental costs	**86**	83
Other liabilities and deferred credits	**198**	161
Liabilities of discontinued operations	**$ 649**	538

In the fourth quarter of 2002, ConocoPhillips concluded a strategic business review of its company-owned retail sites. The review included quantitative and qualitative measures and identified 3,200 retail sites throughout the United States that did not fit the company's long-range plans. The assets are being actively marketed by an investment banking firm. The retail sites are being grouped and marketed in packages, including the planned sale of the company's Circle K Corporation subsidiary. Discussions are under way with potential buyers, and the company expects to complete the sales in 2003.

In connection with the anticipated sale of these retail sites, ConocoPhillips recorded charges totaling $1,412 million before-tax, $1,008 million after-tax, primarily related to the impairment of properties, plants and equipment ($249 million); goodwill ($257 million); intangible asset ($429 million); and provisions for losses and penalties associated with various operating lease commitments ($477 million).

The intangible asset represents the Circle K tradename. Properties, plants and equipment include land, buildings and equipment of owned retail sites and leasehold improvements of leased sites. Fair value determinations were based on estimated sales prices for comparable sites.

The provisions for losses and penalties associated with various operating lease commitments include obligations for residual value guarantee deficiencies, and future minimum rental payments that existed prior to the commitment date that will continue after the exit plan is completed with no economic benefit. It also includes penalties incurred to cancel the contractual arrangements. An additional $130 million of lease loss provisions ($85 million after-tax) will be recognized in 2003 as the company continues to operate the sites until sold.

As a condition to the merger of Conoco and Phillips, the FTC required that the company divest the following assets:

- Phillips' Woods Cross business unit, which includes the Woods Cross, Utah, refinery and associated motor fuel marketing operations (both retail and wholesale) in Utah, Idaho, Wyoming, and Montana, as well as Phillips' 50 percent interests in two refined products terminals in Boise and Burley, Idaho;
- Conoco's Commerce City, Colorado, refinery and related crude oil pipelines;
- Phillips' Colorado motor fuel marketing operations (both retail and wholesale);
- Phillips' refined products terminal in Spokane, Washington;
- Phillips' propane terminal assets at Jefferson City, Missouri, and East St. Louis, Illinois, which include the propane portions of these terminals and the customer relationships and contracts for the supply of propane therefrom;
- certain of Conoco's midstream natural gas gathering and processing assets in southeast New Mexico; and
- certain of Conoco's midstream natural gas gathering assets in West Texas.

Further, the FTC required that certain of these assets be held separately within ConocoPhillips, under the management of a trustee until sold. In connection with these anticipated sales, ConocoPhillips recorded an impairment of $113 million before-tax, $69 million after-tax, related to the Phillips assets in the third quarter of 2002.

In the fourth quarter of 2002, ConocoPhillips agreed to sell its Woods Cross business unit for $25 million, subject to an adjustment for certain pension obligations and the value of crude oil, refined products and other inventories. Also in the fourth quarter, the company sold its propane terminal assets at Jefferson City, Missouri, and East St. Louis, Illinois. The sales amounts did not differ significantly from the fair-value estimates used in the third quarter impairment calculations. Sale of the Colorado assets and the midstream assets is expected to occur in 2003.

The company's Netherlands exploration and production assets were sold in the fourth quarter of 2002. No gain or loss was recognized on the sale, as these assets were recorded at fair value in the Conoco purchase price allocation.

Note 5 — Restructuring

As a result of the merger, the company implemented a restructuring program in September 2002 to capture the synergies of combining the two companies. In connection with this program, the company recorded accruals totaling $770 million for anticipated employee severance payments, incremental pension and medical plan benefit costs associated with the work force reductions, site closings, and Conoco employee relocations. Of the total accrual, $337 million is reflected in the Conoco purchase price allocation as an assumed liability, and $422 million ($253 million after-tax) related to Phillips is reflected in selling, general and administrative expense and production and operating expense, and $11 million before-tax is included in discontinued operations.

Included in the total accruals of $770 million was $172 million related to pension and other post-retirement benefits that will be paid in conjunction with other retirement benefits over a number of future years. The table below summarizes the balance of the accrual of $598 million, which consists of severance related benefits to be provided to approximately 2,900 employees worldwide and other merger related expenses. By the end of 2002, approximately 775 employees had been terminated. Changes in the severance related accrual balance are summarized below.

	Millions of Dollars		
	2002 Accruals	Benefit Payments	Reserve at December 31, 2002
Conoco	$ 297*	(191)	106
Phillips	301	(32)	269
Total	$ 598	(223)	375

**Purchase price adjustment.*

The ending accrual balance is expected to be extinguished within one year, except for $37 million, which is classified as long-term.

Note 6 — Acquisition of Tosco Corporation

On September 14, 2001, Tosco was merged with a subsidiary of ConocoPhillips, as a result of which ConocoPhillips became the owner of 100 percent of the outstanding common stock of Tosco. Tosco's results of operations have been included in ConocoPhillips' consolidated financial statements since that date. Tosco's operations included seven U.S. refineries with a total crude oil capacity of 1.31 million barrels per day; one 75,000-barrel-per-day refinery located in Cork, Ireland; and various marketing, transportation, distribution and corporate assets.

The primary reasons for ConocoPhillips' acquisition of Tosco, and the primary factors that contributed to a purchase price that resulted in recognition of goodwill, are:

- the Tosco operations would deliver earnings prospects, and potential strategic and other benefits;
- combining the two companies' operations would provide significant cost savings;
- adding Tosco to ConocoPhillips' Refining and Marketing (R&M) operations would give the segment the size, scale and resources to compete more effectively;
- the merger would transform ConocoPhillips into a stronger, more integrated oil company with the benefits of increased size and scale, improving the stability of the combined business' earnings in varying economic and market climates;
- the combined company would have a stronger balance sheet, improving its access to capital in the future; and
- the increased cash flow and access to capital resulting from the Tosco acquisition would allow ConocoPhillips to pursue other opportunities in the future.

Based on an exchange ratio of 0.8 shares of ConocoPhillips common stock for each Tosco share, ConocoPhillips issued approximately 124.1 million common shares and 4.7 million vested employee stock options in the exchange, which increased common stockholders' equity by approximately $7 billion. The common stock was valued at $55.50 per share, which was ConocoPhillips' average common stock price over the two-day trading period before and after the February 4, 2001, public announcement of the transaction. The employee stock options were valued using the Black-Scholes option pricing model, based on assumptions prevalent at the February 2001 announcement date.

The allocation of the purchase price to specific assets and liabilities was based, in part, upon an outside appraisal of Tosco's long-lived assets. Goodwill and indefinite-lived intangible assets recorded in the acquisition are not subject to amortization, but the goodwill and intangible assets will be tested periodically for impairment as required by SFAS No. 142, "Goodwill and Other Intangible Assets."

During the third quarter of 2002, the company concluded:

- the outside appraisal of the long-lived assets;
- the determination of the fair value of all other Tosco assets and liabilities;
- the tax basis calculation of Tosco's assets and liabilities and the related deferred tax liabilities; and
- the allocation of Tosco goodwill to reporting units within the R&M operating segment.

The resulting adjustments to the purchase price allocation made in 2002 increased goodwill by $341 million. The more significant adjustments to goodwill were a $247 million reduction in the value of refinery air emission permits to reflect a more appropriate appraisal methodology, a $70 million liability recorded for Tosco Long-Term Incentive Plan performance units, and a $69 million increase in deferred tax liabilities, resulting primarily from an updated analysis of the tax bases of Tosco's assets and liabilities. All other adjustments in the aggregate reduced goodwill by $45 million.

Tosco Long-Term Incentive Plan performance units were derivative financial instruments tied to ConocoPhillips' stock price and were marked-to-market each reporting period. The resulting gains or losses from these mark-to-market adjustments were reported in other income in the consolidated statement of operations. In October 2002, the company and former Tosco executives negotiated a complete cancellation of the performance units in exchange for a cash payment to the former executives. During 2002, the company recorded gains totaling $38 million, after-tax, as this liability was marked-to-market each reporting period and eventually settled.

The following table summarizes, based on the final purchase price allocation described above, the fair values of the assets acquired and liabilities assumed as of September 14, 2001:

	Millions of Dollars
Cash and cash equivalents	$ 103
Accounts and notes receivable	718
Inventories	1,965
Prepaid expenses and other current assets	154
Investments and long-term receivables	150
Properties, plants and equipment (including $1,720 million of land)	7,681
Goodwill	2,644
Intangibles	1,003
Other assets	11
Total assets	$14,429

	Millions of Dollars
Accounts payable	$ 1,917
Accrued income and other taxes	350
Other accruals	206
Long-term debt	2,135
Accrued environmental costs	332
Deferred income taxes	1,824
Employee benefit obligations	177
Other liabilities and deferred credits	408
Common stockholders' equity	7,080
Total liabilities and equity	$14,429

Of the $1,003 million allocated to intangible assets, marketing tradenames comprised $655 million, refinery air emission and operating permits totaled $315 million and other miscellaneous intangible assets amounted to $33 million. The $1,003 million of intangible assets included $992 million allocated to indefinite-lived intangible assets not subject to amortization and $11 million allocated to intangible assets with a weighted-average amortization period of seven years. In late 2002, the Circle K tradename ($429 million) was included with the retail marketing operations that are held for sale at December 31, 2002, and included in the loss on disposal. See Note 4 — Discontinued Operations.

ConocoPhillips finalized the required assignment of Tosco goodwill to specific reporting units in 2002, with $1,944 million assigned to the refining reporting unit and $700 million assigned to the marketing reporting unit. The goodwill was assigned to the reporting units that were deemed to have benefited from the synergies and strategic advantages of the merger. In late 2002, $257 million of goodwill assigned to the marketing reporting unit was allocated to the retail marketing operations held for sale at December 31, 2002, and included in the loss on disposal. See Note 4 — Discontinued Operations.

Note 7 — Inventories

Inventories at December 31 were:

	Millions of Dollars	
	2002	2001
Crude oil and petroleum products	**$ 3,395**	2,231
Canadian Syncrude (from mining operations)	**4**	—
Materials, supplies and other	**446**	221
	$ 3,845	2,452

Inventories valued on a LIFO basis totaled $3,349 million and $2,211 million at December 31, 2002 and 2001, respectively. The remainder of the company's inventories are valued under various other methods, including FIFO and weighted average. The excess of current replacement cost over LIFO cost of inventories amounted to $1,083 million and $2 million at December 31, 2002 and 2001, respectively.

In the fourth quarter of 2001, the company recorded a $42 million before-tax, $27 million after-tax, lower-of-cost-or-market write-down of its petroleum products inventory. During 2000, certain inventory quantity reductions caused a liquidation of LIFO inventory values. This liquidation increased net income by $63 million, of which $60 million was attributable to ConocoPhillips' R&M segment.

Note 8 — Investments and Long-Term Receivables

Components of investments and long-term receivables at December 31 were:

	Millions of Dollars	
	2002	2001
Investments in and advances to affiliated companies	**$ 5,900**	2,788
Long-term receivables	**526**	241
Other investments	**395**	280
	$ 6,821	3,309

At December 31, 2002, retained earnings included $825 million related to the undistributed earnings of affiliated companies, and distributions received from affiliates were $313 million, $163 million and $2,180 million in 2002, 2001 and 2000, respectively.

Equity Investments

The company owns or owned investments in chemicals, heavy-oil projects, oil and gas transportation, coal mining and other industries. The affiliated companies for which ConocoPhillips uses the equity method of accounting include, among others, the following companies: Chevron Phillips Chemical Company LLC (CPChem) (50 percent), Duke Energy Field Services, LLC (DEFS) (30.3 percent), Petrozuata C.A. (50.1 percent non-controlling interest), Merey Sweeny L.P. (MSLP) (50 percent), Petrovera Resources Limited (46.7 percent), and Hamaca Holding LLC (57.1 percent non-controlling interest). See Note 1 — Accounting Policies for additional information.

Summarized 100 percent financial information for DEFS, CPChem and all other equity companies accounted for using the equity method follows:

2002	Millions of Dollars			
	DEFS	CPChem	Other Equity Companies	Total
Revenues	**$5,492**	**5,473**	**5,378**	**16,343**
Income (loss) before income taxes	**(37)**	**(24)**	**776**	**715**
Net income (loss)	**(47)**	**(30)**	**751**	**674**
Current assets	**1,123**	**1,561**	**5,783**	**8,467**
Noncurrent assets	**5,457**	**4,548**	**14,386**	**24,391**
Current liabilities	**1,426**	**1,051**	**4,696**	**7,173**
Noncurrent liabilities	**2,504**	**1,307**	**10,063**	**13,874**

2001	Millions of Dollars			
	DEFS	CPChem	Other Equity Companies	Total
Revenues	$8,025	6,010	1,555	15,590
Income (loss) before income taxes	367	(431)	607	543
Net income (loss)	364	(480)	414	298
Current assets	1,165	1,551	689	3,405
Noncurrent assets	5,465	4,309	3,949	13,723
Current liabilities	1,251	820	1,184	3,255
Noncurrent liabilities	2,426	1,606	1,960	5,992

2000	Millions of Dollars			
	DEFS*	CPChem**	Other Equity Companies	Total
Revenues	$5,099	3,463	3,241	11,803
Income (loss) before income taxes	321	(213)	611	719
Net income (loss)	318	(241)	412	489

**For the period April 1, 2000, through December 31, 2000.*
***For the period July 1, 2000, through December 31, 2000.*

ConocoPhillips' share of income taxes incurred directly by the equity companies is reported in equity in earnings of affiliates, and as such is not included in income taxes in ConocoPhillips' consolidated financial statements.

Duke Energy Field Services, LLC

On March 31, 2000, ConocoPhillips combined its midstream gas gathering, processing and marketing business with the gas gathering, processing, marketing and natural gas liquids business of Duke Energy Corporation (Duke Energy) forming a new company, DEFS. Duke Energy owns 69.7 percent of the company, which it consolidates, while ConocoPhillips owns 30.3 percent, which it accounts for using the equity method.

Duke Energy estimated the fair value of the ConocoPhillips' midstream business at $1.9 billion in its purchase method accounting for the acquisition. The book value of the midstream business contributed to DEFS was $1.1 billion, but no gain was recognized in connection with the transaction because of ConocoPhillips' and CPChem's long-term commitment to purchase the natural gas liquids output from the former ConocoPhillips' natural gas processing plants until December 31, 2014. This purchase commitment is on an "if-produced, will-purchase" basis so it has no fixed production schedule, but has been, and is expected to be, a relatively stable purchase pattern over the term of the contract. Natural gas liquids are purchased under this agreement at various published market index prices, less transportation and fractionation fees. ConocoPhillips' consolidated results of operations include 100 percent of the activity of the gas gathering, processing and marketing business contributed to DEFS through March 31, 2000, and its 30.3 percent share of DEFS' earnings since that date.

At December 31, 2002, the book value of ConocoPhillips' common investment in DEFS was $67 million. ConocoPhillips' 30.3 percent share of the net assets of DEFS was $743 million. This basis difference of $676 million, is being amortized on a straight-line basis over 15 years, consistent with the remaining estimated useful lives of the properties, plants and equipment contributed to DEFS. Included in operating results for 2002, 2001 and 2000 was after-tax income of $35 million, $36 million and $27 million, respectively, representing the amortization of the basis difference.

On August 4, 2000, DEFS, Duke Energy and ConocoPhillips agreed to modify the Limited Liability Company Agreement governing DEFS to provide for the admission of a class of preferred members in DEFS. Subsidiaries of Duke Energy and ConocoPhillips purchased new preferred member interests for $209 million and $91 million, respectively. The preferred member interests have a 30-year term, will pay a distribution yielding 9.5 percent annually, and contain provisions that require their redemption with any proceeds from an initial public offering. On September 9, 2002, ConocoPhillips received $30 million return of preferred member interest reducing its preferred interest to $61 million.

Chevron Phillips Chemical Company LLC

On July 1, 2000, ConocoPhillips and ChevronTexaco Corporation, as successor to Chevron Corporation (ChevronTexaco), combined their worldwide chemicals businesses, excluding ChevronTexaco's Oronite business, into a new company, CPChem. In addition to contributing the assets and operations included in the company's Chemicals segment, ConocoPhillips also contributed the natural gas liquids business associated with its Sweeny, Texas, complex. ConocoPhillips and ChevronTexaco each own 50 percent of the voting and economic interests in CPChem, and on July 1, 2000, ConocoPhillips began accounting for its investment in CPChem using the equity method. Accordingly, ConocoPhillips' results of operations include 100 percent of the activity of its chemicals business through June 30, 2000, and its 50 percent share of CPChem's earnings since that date. CPChem accounted for the combination using the historical bases of the assets and liabilities contributed by ConocoPhillips and ChevronTexaco.

At December 31, 2002, the book value of ConocoPhillips' investment in CPChem was $1,919 million. ConocoPhillips' 50 percent share of the total net assets of CPChem was $1,747 million. This basis difference of $172 million is being amortized over 20 years, consistent with the remaining estimated useful lives of the properties, plants and equipment contributed to CPChem.

On July 1, 2002, ConocoPhillips purchased $125 million of Members' Preferred Interests. Preferred distributions are cumulative at 9 percent per annum and will be payable quarterly, upon declaration by CPChem's Board of Directors, from CPChem's cash earnings. The securities have no stated maturity date and are redeemable quarterly, in increments of $25 million, when CPChem's ratio of debt to total capitalization falls below a stated level. The Members' Preferred Interests are also redeemable at CPChem's sole option at any time.

Note 9 — Properties, Plants and Equipment, Goodwill and Intangibles

The company's investment in properties, plants and equipment (PP&E), with accumulated depreciation, depletion and amortization (DD&A), at December 31 was:

	Millions of Dollars					
	2002			2001		
	Gross PP&E	DD&A	Net PP&E	Gross PP&E	DD&A	Net PP&E
E&P	**$36,884**	**8,600**	**28,284**	20,995	7,870	13,125
Midstream	**903**	**16**	**887**	49	34	15
R&M	**15,605**	**2,765**	**12,840**	11,553	2,804	8,749
Chemicals	**—**	**—**	**—**	—	—	—
Emerging Businesses	**690**	**5**	**685**	—	—	—
Corporate and Other	**477**	**143**	**334**	493	249	244
	$54,559	**11,529**	**43,030**	33,090	10,957	22,133

Changes in the carrying amount of goodwill are as follows:

	Millions of Dollars			
	E&P	R&M	Corporate	Total
Balance at December 31, 2000	$ —	—	—	—
Acquired (primarily Tosco acquisition)	15	2,266	—	2,281
Balance at December 31, 2001	15	2,266	—	2,281
Acquired (merger of Conoco and Phillips)*	—	—	**12,079**	**12,079**
Valuation and other adjustments	—	**341**	—	**341**
Allocated to discontinued operations	—	**(257)**	—	**(257)**
Balance at December 31, 2002	**$ 15**	**2,350**	**12,079**	**14,444**

**Has not yet been allocated to reporting units.*

Information on the carrying value of intangible assets at December 31 follows:

	Millions of Dollars	
	2002	2001
Amortized Intangible Assets		
Refining technology related	**$ 78**	—
Other	**44**	11
	$122	11
Unamortized Intangible Assets		
Tradenames	**$669**	226
Refinery air and operating permits	**315**	562
Other	**13**	62
	$997	850

Note 10 — Impairments

During 2002, 2001 and 2000, the company recognized the following before-tax impairment charges:

	Millions of Dollars		
	2002	2001	2000
E&P			
United States	**$ 12**	3	13
International	**37**	23	87
R&M			
Tradenames	**102**	—	—
Retail site leasehold improvements	**26**	—	—
	$177	26	100

After-tax, the above impairment charges were $115 million in 2002, $25 million in 2001, and $95 million in 2000.

The company's E&P segment recognized impairments of $49 million before-tax on four fields in 2002. Impairment of the Janice field in the U.K. North Sea was triggered by its sale, while the Viscount field in the U.K. North Sea was impaired following an evaluation of development drilling results. Sales of properties in Alaska and offshore California resulted in the remaining E&P impairments in 2002.

The company initiated a plan in late 2002 to sell a substantial portion of its R&M retail sites. The planned dispositions will result in a reduction of the amount of gasoline volumes marketed under the company's "76" tradename. As a result, the carrying value of the "76" tradename was impaired, with the $102 million impairment determined by an analysis of the discounted cash flows based on the gasoline volumes projected to be sold under the brand name after the planned dispositions, compared with the volumes being sold prior to the dispositions. The company also impaired the carrying value of certain leasehold improvements associated with leased retail sites that are held for use. The impairment was triggered by a review of the leased-site guaranteed residual values and was determined by comparing the guaranteed residual values and leasehold improvements with current market values of the related assets.

See Note 4 — Discontinued Operations for information regarding the impairments recognized in 2002 in connection with the anticipated sale of certain assets mandated by the FTC, and the planned sale of a substantial portion of the company's retail marketing operations.

In the second quarter of 2001, the company committed to a plan to sell its 12.5 percent interest in the Siri oil field, offshore Denmark, triggering a write-down of the field's assets to fair market value. The sale closed in early 2002. The company also recorded a property impairment on a crude oil tanker that was sold in the fourth quarter of 2001.

The company recorded an impairment of its Ambrosio field, located in Lake Maracaibo, Venezuela, in 2000. The Ambrosio field exploitation program did not achieve originally premised results. The $87 million impairment charge was based on the difference between the net book value of the property and the discounted value of estimated future cash flows. The remaining property impairments in 2000 were related to fields in the United States, and were prompted by an evaluation of drilling results or negative oil and gas reserve revisions.

Note 11 — Accrued Dismantlement, Removal and Environmental Costs

Accrued Dismantlement and Removal Costs

At December 31, 2002 and 2001, the company had accrued $1,065 million and $776 million, respectively, of dismantlement and removal costs, primarily related to worldwide offshore production facilities and to production facilities in Alaska. The increase in 2002 was primarily due to the merger and increased cost estimates related to production facilities in Alaska. Estimated uninflated total future dismantlement and removal costs at December 31, 2002, were $4,751 million, compared with $2,827 million in 2001. The increase was partially due to the merger. The remaining increase was primarily attributable to changes in future dismantlement and removal cost estimates.

These costs are accrued primarily on the unit-of-production method. Pursuant to SFAS No. 143, "Accounting for Asset Retirement Obligations," the accounting for these costs was changed effective January 1, 2003. See Note 27 — New Accounting Standards for additional information.

Environmental Costs

Total environmental accruals at December 31, 2002 and 2001, were $743 million and $439 million, respectively. The 2002 increase in accrued environmental costs was primarily the result of the merger. A large portion of these accrued environmental costs were acquired in various business combinations and thus are discounted obligations. For the discounted accruals, expected inflated expenditures are: $112 million in 2003, $71 million in 2004, $58 million in 2005, $54 million in 2006, and $53 million in 2007. Remaining expenditures in all future years after 2007 are expected to total $399 million. These expected expenditures are discounted using a weighted-average 5 percent discount factor, resulting in an accrued balance of $675 million at December 31, 2002.

ConocoPhillips had accrued environmental costs, primarily related to cleanup at domestic refineries and underground storage tanks at U.S. service stations, and remediation activities required by the state of Alaska at exploration and production sites formerly owned by Atlantic Richfield Company, of $427 million and $288 million at December 31, 2002 and 2001, respectively. ConocoPhillips had also accrued at corporate $236 million and $136 million of environmental costs associated with non-operating sites at December 31, 2002 and 2001, respectively. In addition, $70 million and $12 million were included at December 31, 2002 and 2001, respectively, for sites where the company has been named a potentially responsible party under the Federal Comprehensive Environmental Response, Compensation and Liability Act, the Federal Resource Conservation and Recovery Act, or similar state laws. At December 31, 2002 and 2001, $10 million and $3 million, respectively, had been accrued for other environmental litigation. Accrued environmental liabilities will be paid over periods extending up to 30 years.

Of the total $1,808 million and $1,215 million of accrued dismantlement, removal and environmental costs at December 31, 2002 and 2001, $142 million and $156 million was classified as a current liability on the balance sheet, under the caption "Other accruals."

Note 12 — Debt

Long-term debt at December 31 was:

	Millions of Dollars	
	2002	2001
9 3/8% Notes due 2011	**$ 350**	350
8.86% Notes due 2022	**—**	250
8.75% Notes due 2010	**1,350**	1,350
8.5% Notes due 2005	**1,150**	1,150
8.49% Notes due 2023	**250**	250
8.25% Mortgage Bonds due 2003	**150**	150
8.125% Notes due 2030	**600**	600
7.92% Notes due 2023	**250**	250
7.9% Notes due 2047	**100**	100
7.8% Notes due 2027	**300**	300
7.68% Notes due 2012	**64**	—
7.625% Notes due 2006	**240**	240
7.25% Notes due 2007	**200**	200
7.25% Notes due 2031	**500**	—
7.20% Notes due 2023	**250**	250
7.125% Debentures due 2028	**300**	300
7% Debentures due 2029	**200**	200
6.95% Notes due 2029	**1,900**	—
6.65% Notes due 2003	**100**	100
6.65% Debentures due 2018	**300**	300
6.375% Notes due 2009	**300**	300
6.35% Notes due 2011	**1,750**	—
6.35% Notes due 2009	**750**	—
5.90% Notes due 2004	**1,350**	—
5.90% Notes due 2032	**600**	—
5.45% Notes due 2006	**1,250**	—
4.75% Notes due 2012	**1,000**	—
3.625% Notes due 2007	**400**	—
Commercial paper and revolving debt due to banks and others through 2006 at 1.46% – 1.94% at year-end 2002	**1,517**	1,081
SRW Cogeneration Limited Partnership	**180**	—
Floating Rate Notes due 2003	**500**	—
Industrial Development bonds	**153**	55
Guarantee of LTSSP bank loan payable at 1.69% at year-end 2002	**299**	322
Note payable to Merey Sweeny, L.P. at 7%	**131**	133
Marine Terminal Revenue Refunding Bonds at 2.9% – 3.1% at year-end 2002	**265**	265
Other notes payable	**68**	49
Debt at face value	**19,067**	8,545
Capitalized leases	**23**	—
Net unamortized premium and discounts	**676**	109
Total debt	**19,766**	8,654
Notes payable and long-term debt due within one year	**(849)**	(44)
Long-term debt	**$18,917**	8,610

Maturities inclusive of net unamortized premiums and discounts in 2003 through 2007 are: $849 million (included in current liabilities), $1,438 million, $1,229 million, $3,173 million and $654 million, respectively.

The company assumed $12,031 million of debt in connection with the merger.

In October 2002, ConocoPhillips entered into two new revolving credit facilities and amended and restated a prior Phillips revolving credit facility to include ConocoPhillips as a borrower. These credit facilities support the company's $4 billion commercial paper program, a portion of which may be denominated in euros (limited to euro 3 billion). The company now has a $2 billion 364-day revolving credit facility expiring on October 14, 2003, and two revolving credit facilities totaling $2 billion expiring in October 2006. Effective with the execution of the new facilities, the previously existing $2.5 billion in Conoco facilities were terminated.

At December 31, 2002, ConocoPhillips had no debt outstanding under these credit facilities, but had $1,517 million in commercial paper outstanding, which is supported 100 percent by the long-term credit facilities. This amount approximates fair value.

As of December 31, 2002, the company's wholly owned subsidiary, ConocoPhillips Norway, had no outstanding debt under its two $300 million revolving credit facilities expiring in June 2004.

Depending on the credit facility, borrowings may bear interest at a margin above rates offered by certain designated banks in the London interbank market or at margins above certificate of deposit or prime rates offered by certain designated banks in the United States. The agreements call for commitment fees on available, but unused, amounts. The agreements also contain early termination rights if the company's current directors or their approved successors cease to be a majority of the Board of Directors.

In October 2002, ConocoPhillips privately placed $2 billion of senior unsecured debt securities, consisting of $400 million 3.625% notes due 2007, $1 billion 4.75% notes due 2012, and $600 million 5.90% notes due 2032, in each case fully and unconditionally guaranteed by Conoco and Phillips. The $1,980 million proceeds from the offering were used to reduce commercial paper, retire Conoco's $500 million floating rate notes due October 15, 2002, and for general corporate purposes.

ConocoPhillips redeemed the following notes during 2002 and early 2003 and funded the redemptions with commercial paper:

- on May 15, 2002, its $250 million 8.86% notes due May 15, 2022, at 104.43 percent, resulting in a second quarter extraordinary loss from the early retirement of debt of $13 million before-tax, $9 million after-tax;
- on November 26, 2002, its $171 million 7.443% senior unsecured notes due 2004 resulting in a fourth quarter extraordinary loss from the early retirement of debt of $3 million before-tax, $1 million after-tax;
- on January 1, 2003, its $250 million 8.49% notes due January 1, 2023, at 104.245 percent; and
- on January 31, 2003, its $181 million SRW Cogeneration Limited Partnership note which was assumed in September 2002 as a result of acquiring its partners' interest in the partnership.

At December 31, 2002, $299 million was outstanding under the company's Long-Term Stock Savings Plan (LTSSP) term loan, which will require annual installments beginning in 2008 and continue through 2015. Under this bank loan, any participating bank in the syndicate of lenders may cease to participate on December 5, 2004, by giving not less than 180 days' prior notice to the LTSSP and the company. If participating lenders give the cessation notice, the company plans to resyndicate the loan.

Each bank participating in the LTSSP loan has the optional right, if the current company directors or their approved successors cease to be a majority of the Board, and upon not less than 90 days' notice, to cease to participate in the loan. Under the above conditions, such banks' rights and obligations under the loan agreement must be purchased by the company if not transferred to a bank of the company's choice. See Note 20 — Employee Benefit Plans for additional discussion of the LTSSP.

Note 13 — Sales of Receivables

At December 31, 2002, ConocoPhillips sold certain credit card and trade receivables to two Qualifying Special Purpose Entities (QSPEs) in revolving-period securitization arrangements. These arrangements provide for ConocoPhillips to sell, and the QSPEs to purchase, certain receivables and for the QSPEs to then issue beneficial interests of up to $1.5 billion to five bank-sponsored entities. The receivables sold have been sufficiently isolated from ConocoPhillips to qualify for sales treatment. All five bank-sponsored entities are multi-seller conduits with access to the commercial paper market and purchase interests in similar receivables from numerous other companies unrelated to ConocoPhillips. ConocoPhillips has no ownership in any of the bank-sponsored entities and has no voting influence over any bank-sponsored entity's operating and financial decisions. As a result, ConocoPhillips does not consolidate any of these entities. Beneficial interests retained by ConocoPhillips in the pool of receivables held by the QSPEs are subordinate to the beneficial interests issued to the bank-sponsored entities and were measured and recorded at fair value based on the present value of future expected cash flows estimated using management's best estimates concerning the receivables performance, including credit losses and dilution discounted at a rate commensurate with the risks involved to arrive at present value. These assumptions are updated periodically based on actual credit loss experience and market interest rates. ConocoPhillips also retains servicing responsibility related to the sold receivables. The fair value of the servicing responsibility approximates adequate compensation for the servicing costs incurred. ConocoPhillips' retained interest in the sold receivables at December 31, 2002 and 2001, was $1.3 billion and $450 million, respectively. Under accounting principles generally accepted in the United States, the QSPEs are not consolidated by ConocoPhillips. ConocoPhillips retained interest in sold receivables is reported on the balance sheet in accounts and notes receivable — related parties.

Total cash flows received from and paid under the securitization arrangements were as follows:

	Millions of Dollars	
	2002	2001
Receivables sold at beginning of year	**$ 940**	500
Conoco receivables sold at August 30, 2002	**400**	—
Tosco receivables sold at September 14, 2001	**—**	614
New receivables sold	**18,613**	8,907
Cash collections remitted	**(18,630)**	(9,081)
Receivables sold at end of year	**$ 1,323**	940
Discounts and other fees paid on revolving balances	**$ 21**	24

At year-end, ConocoPhillips sold $264 million of receivables under a factoring arrangement. ConocoPhillips also retains servicing responsibility related to the sold receivables. The fair value of the servicing responsibility approximates adequate compensation for the servicing costs incurred. At maturity of the receivables, ConocoPhillips has a recourse obligation to repurchase uncollected receivables. The fair value of this recourse obligation is not significant.

Note 14 — Guarantees

At December 31, 2002, the company was liable for certain contingent obligations under various contractual arrangements as described below.

Construction Completion Guarantees

- The company has a construction completion guarantee related to debt and bond financing arrangements secured by the Merey

Sweeny, L.P. (MSLP) joint-venture project in Texas. The maximum potential amount of future payment under the guarantee, including joint-and-several debt at its gross amount, is estimated to be $418 million assuming that completion certification is not achieved. Of this amount, $209 million is attributable to Petroleos de Venezuela, S.A. (PDVSA), because they are joint-and-severally liable for a portion of the debt. If completion certification is not attained by 2004, the full debt balance is due. The debt is non-recourse to ConocoPhillips upon completion certification.

- The company has issued a construction completion guarantee related to debt financing arrangements for the Hamaca Holding LLC joint venture project in Venezuela. The maximum potential amount of future payments under the guarantee is estimated to be $441 million, which could be payable if the full debt financing capacity is utilized and startup and completion of the Hamaca project is not achieved by October 1, 2005. The project financing debt is non-recourse to ConocoPhillips upon startup and completion certification.

Guaranteed Residual Value on Leases

- The company leases ocean transport vessels, drillships, tank railcars, corporate aircraft, service stations, computers, office buildings, certain refining equipment, and other facilities and equipment. Associated with these leases the company has guaranteed approximately $1,821 million in residual values, which are due at the end of the lease terms. However, those guaranteed amounts would be reduced by the fair market value of the leased assets returned. See Note 19 — Non-Mineral Leases.

Guarantees of Joint-Venture Debt

- At December 31, 2002, ConocoPhillips had guarantees of about $355 million outstanding for its portion of joint-venture debt obligations. Of that amount, $176 million is associated with the Polar Lights Company joint-venture project in Russia. Smaller amounts and in some cases debt service reserves are associated with Interconnector (UK) Ltd., Turcas Petrol, Malaysian Refining Company Sdn. Bhd (Melaka), Hydroserve, Excel Paralubes, and Ingleside Cogeneration Limited Partnership. The various debt obligations have terms of up to 24 years.

Other Guarantees

- In addition to the construction completion guarantee explained above, the MSLP agreement also requires the partners in the venture to pay cash calls as required to meet minimum operating requirements of the venture, in the event revenues do not cover expenses over the next 18 years. The maximum potential future payments under the agreement are estimated to be $258 million assuming MSLP does not earn any revenue over the entire period. To the extent revenue was generated by the venture, future required payments would be reduced accordingly.
- The company has guaranteed certain potential payments related to its interest in two drillships, which are operated by joint ventures. Potential payments could be required for guaranteed residual value amounts and amounts due under interest rate hedging agreements. The maximum potential future payments under the agreements are estimated to be approximately $193 million.
- During 2001, the company entered into a letter agreement authorizing the charter, by an unaffiliated third party, of up to four LNG vessels, which included an indemnity by the company in respect of claims for charter hire and other charter payments. The indemnity was subject to certain limitations and was to be applied net of sub-charter rental income and other receipts of the unaffiliated third party. In February 2003, the company entered into new agreements which cancelled the 2001 letter agreement and established separate guarantee facilities for $50 million each for two of the LNG vessels. Under each such facility, the company may be required to make payments should the charter revenue generated by the relevant ship fall below certain specified minimum thresholds, and the company will receive payments to the extent that such revenues exceed those thresholds. The net maximum future payments over the 20 year terms of the agreements could be up to $100 million. In the event the two ships are sold or a total loss occurs, the company also may have recourse to the sales or insurance proceeds to recoup payments made under the guarantee facilities.
- Other guarantees, consisting primarily of dealer and jobber loan guarantees to support the company's marketing business, a guarantee supporting a lease assignment on a corporate aircraft and guarantees of lease payment obligations for a joint venture totaled $111 million. These guarantees generally extend up to 15 years and payment would only be required if the dealer, jobber or lessee was in default.

Indemnifications

- Over the years, the company has entered into various agreements to sell ownership interests in certain corporations and joint ventures. In addition, the company entered into a Tax Sharing Agreement in 1998 related to Conoco's separation from DuPont. These agreements typically include indemnifications for additional taxes determined to be due under the relevant tax law in connection with the company's operations for years prior to the sale or separation. Generally, the obligation extends until the related tax years are closed. The maximum potential amount of future payments under the indemnifications is the amount of additional tax determined to be due under relevant tax law and the various agreements. There are no material outstanding claims that have been asserted under these agreements.
- As part of its normal ongoing business operations and consistent with generally accepted and recognized industry practice, ConocoPhillips enters into various agreements with other parties (the Agreements). These Agreements apportion future risks between the parties for the transaction(s) or relationship(s) governed by such Agreements; one method of apportioning risk between the company and the other contracting party is the inclusion of provisions requiring one party to indemnify the other party against losses that might otherwise be incurred by such other party in the future (the Indemnity or Indemnities). Many of the company's Agreements contain an Indemnity or Indemnities that require the company to perform certain obligations as a result of the occurrence of a triggering event or condition. In some instances the company indemnifies third parties against losses resulting from certain events or conditions that arise out of operations conducted by the company's equity affiliates.

The nature of these indemnity obligations are diverse and too numerous to list in this disclosure because of the thousands of different Agreements to which the company is a party, each of which may have a different term, business purpose, and triggering events or conditions for an indemnity obligation. Consistent with customary business practice, any particular indemnity obligation incurred by the company is the result of a negotiated transaction or contractual relationship for which the company has accepted a certain level of risk in return for a financial or other type of benefit to the company. In addition, the Indemnity or Indemnities in each Agreement vary widely in their definitions of both the triggering event and the resulting obligation, which is contingent on that triggering event.

The company's risk management philosophy is to limit risk in any transaction or relationship to the maximum extent reasonable in relation to commercial and other considerations. Before accepting any indemnity obligation, the company makes an informed risk management decision considering, among other things, the remoteness of the possibility that the triggering event will occur, the potential costs to perform any resulting indemnity obligation, possible actions to reduce the likelihood of a triggering event or to reduce the costs of performing an indemnity obligation, whether the company is in fact indemnified by an unrelated third party, insurance coverage that may be available to offset the cost of the indemnity obligation, and the benefits to the company from the transaction or relationship.

Because many or most of the company's indemnity obligations are not limited in duration or potential monetary exposure, the company cannot calculate the maximum potential amount of future payments that could be paid under the company's indemnity obligations stemming from all its existing Agreements. The company has disclosed contractual matters, including, but not limited to, indemnity obligations, which will or could have a material impact on the company's financial performance in quarterly, annual and other reports required by applicable securities laws and regulations. The company also accrues for contingent liabilities, including those arising out of indemnity obligations, when a loss is probable and the amounts can be reasonably estimated (see Note 15 — Contingencies). The company is not aware of the occurrence of any triggering event or condition that would have a material adverse impact on the company's financial statements as a result of an indemnity obligation relating to such triggering event or condition.

Note 15 — Contingencies

The company is subject to various lawsuits and claims including but not limited to: actions challenging oil and gas royalty and severance tax payments; actions related to gas measurement and valuation methods; actions related to joint interest billings to operating agreement partners; and claims for damages resulting from leaking underground storage tanks, with related toxic tort claims.

In the case of all known contingencies, the company accrues an undiscounted liability when the loss is probable and the amount is reasonably estimable. These liabilities are not reduced for potential insurance recoveries. If applicable, undiscounted receivables are accrued for probable insurance or other third-party recoveries. Based on currently available information, the company believes that it is remote that future costs related to known contingent liability exposures will exceed current accruals by an amount that would have a material adverse impact on the company's financial statements.

As facts concerning contingencies become known to the company, the company reassesses its position both with respect to accrued liabilities and other potential exposures. Estimates that are particularly sensitive to future changes include contingent liabilities recorded for environmental remediation, tax and legal matters. Estimated future environmental remediation costs are subject to change due to such factors as the unknown magnitude of cleanup costs, the unknown time and extent of such remedial actions that may be required, and the determination of the company's liability in proportion to that of other responsible parties. Estimated future costs related to tax and legal matters are subject to change as events evolve and as additional information becomes available during the administrative and litigation processes.

Environmental — The company is subject to federal, state and local environmental laws and regulations. These may result in obligations to remove or mitigate the effects on the environment of the placement, storage, disposal or release of certain chemical, mineral and petroleum substances at various sites. When the company prepares its financial statements, accruals for environmental liabilities are recorded based on management's best estimate using all information that is available at the time. Loss estimates are measured and liabilities are based on currently available facts, existing technology, and presently enacted laws and regulations, taking into consideration the likely effects of inflation and other societal and economic factors. Also considered when measuring environmental liabilities are the company's prior experience in remediation of contaminated sites, other companies' cleanup experience and data released by the U.S. Environmental Protection Agency (EPA) or other organizations. Unasserted claims are reflected in ConocoPhillips' determination of environmental liabilities and are accrued in the period that they are both probable and reasonably estimable.

Although liability of those potentially responsible for environmental remediation costs is generally joint and several for federal sites and frequently so for state sites, the company is usually only one of many companies cited at a particular site. Due to the joint and several liabilities, the company could be responsible for all of the cleanup costs related to any site at which it has been designated as a potentially responsible party. If ConocoPhillips were solely responsible, the costs, in some cases, could be material to its, or one of its segments', operations, capital resources or liquidity. However, settlements and costs incurred in matters that previously have been resolved have not been materially significant to the company's results of operations or financial condition. The company has been successful to date in sharing cleanup costs with other financially sound companies. Many of the sites at which the company is potentially responsible are still under investigation by the EPA or the state agencies concerned. Prior to actual cleanup, those potentially responsible normally assess the site conditions, apportion responsibility and determine the appropriate remediation. In some instances, ConocoPhillips may have no liability or attain a settlement of liability. Where it appears that other potentially responsible parties may be financially unable to bear their proportional share, this inability has been considered in estimating the company's potential liability and accruals have been adjusted accordingly.

Upon ConocoPhillips' acquisition of Tosco on September 14, 2001, the assumed environmental obligations of Tosco, some of which are mitigated by indemnification agreements, became contingencies reportable on a consolidated basis by ConocoPhillips. Beginning with the acquisition of the Bayway refinery in 1993, but excluding the Alliance refinery acquisition, Tosco negotiated, as part of its acquisitions, environmental indemnification from the former owners for remediating contamination that occurred prior to the respective acquisition dates. Some of the environmental indemnifications are subject to caps and time limits. No accruals have been recorded for any potential contingent liabilities that will be funded by the prior owners under these indemnifications.

As part of Tosco's acquisition of Unocal's West Coast petroleum refining, marketing, and related supply and transportation assets in March 1997, Tosco agreed to pay the first $7 million per year of any environmental remediation liabilities at the acquired sites arising out of, or relating to, the period prior to the transaction's closing, plus 40 percent of any amount in excess of $7 million per year, with Unocal paying the remaining 60 percent per year. The indemnification agreement with Unocal has a 25-year term from inception, and, at December 31, 2002, had a maximum cap of $131 million for environmental remediation costs that ConocoPhillips would be required to fund during the remainder of the agreement period. This maximum has been adjusted for amounts paid through December 31, 2002.

The company is currently participating in environmental assessments and cleanups at federal Superfund and comparable state sites. After an assessment of environmental exposures for cleanup and other costs, the company makes accruals on an undiscounted basis (except, if assumed in a purchase business combination, such costs are recorded on a discounted basis) for planned investigation and remediation activities for sites where it is probable that future costs will be incurred and these costs can be reasonably estimated. See Note 11 — Accrued Dismantlement, Removal and Environmental Costs for a summary of the company's accrued environmental liabilities.

Other Legal Proceedings — ConocoPhillips is a party to a number of other legal proceedings pending in various courts or agencies for which, in some instances, no provision has been made.

Other Contingencies — ConocoPhillips has contingent liabilities resulting from throughput agreements with pipeline and processing companies. Under these agreements, ConocoPhillips may be required to provide any such company with additional funds through advances and penalties for fees related to throughput capacity not utilized by ConocoPhillips.

ConocoPhillips has various purchase commitments for materials, supplies, services and items of permanent investment incident to the ordinary conduct of business. Such commitments are not at prices in excess of current market. Additionally, the company has obligations under an international contract to purchase natural gas over a period of up to 17 years. These long-term purchase obligations are at prices in excess of December 31, 2002, quoted market prices. No material annual gain or loss is expected from these long-term commitments.

Note 16 — Financial Instruments and Derivative Contracts

Derivative Instruments

The company and certain of its subsidiaries may use financial and commodity-based derivative contracts to manage exposures to fluctuations in foreign currency exchange rates, commodity prices, and interest rates, or to exploit market opportunities. With the completion of the merger of Phillips and Conoco on August 30, 2002, the derivatives policy adopted during the third quarter of 2001 is no longer in effect; however, the ConocoPhillips Board of Directors has approved an "Authority Limitations" document that prohibits the use of highly leveraged derivatives or derivative instruments without sufficient liquidity for comparable valuations without approval from the Chief Executive Officer. The Authority Limitations document also authorizes the Chief Executive Officer to establish the maximum Value at Risk (VaR) limits for the company. Compliance with these limits is monitored daily. The function of the Risk Management Steering Committee, monitoring the use and effectiveness of derivatives, was assumed by the Chief Financial Officer for risks resulting from foreign currency exchange rates and interest rates, and by the Executive Vice President of Commercial, a new position that reports to the Chief Executive Officer, for commodity price risk. ConocoPhillips' Commercial Group manages commercial marketing, optimizes the commodity flows and positions of the company, monitors related risks of the company's upstream and downstream businesses and selectively takes price risk to add value.

SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended (Statement No. 133 or SFAS No. 133), requires companies to recognize all derivative instruments as either assets or liabilities on the balance sheet at fair value. Assets and liabilities resulting from derivative contracts open at December 31, 2002, were $197 million and $206 million, respectively, and appear as accounts and notes receivables, other assets, accounts payable, or other liabilities and deferred credits on the balance sheet.

The accounting for changes in fair value (i.e., gains or losses) of a derivative instrument depends on whether it meets the qualifications for, and has been designated as, a SFAS No. 133 hedge, and the type of hedge. At this time, ConocoPhillips is not using SFAS No. 133 hedge accounting for commodity derivative contracts, but the company is using hedge accounting for the interest-rate derivatives noted below. All gains and losses, realized or unrealized, from derivative contracts not designated as SFAS No. 133 hedges have been recognized in the statement of operations. Gains and losses from derivative contracts held for trading not directly related to the company's physical business, whether realized or unrealized, have been reported net in other income.

SFAS No. 133 also requires purchase and sales contracts for commodities that are readily convertible to cash (e.g., crude oil, natural gas, and gasoline) to be recorded on the balance sheet as derivatives unless the contracts are for quantities expected to be used or sold by the company over a reasonable period in the normal course of business (the normal purchases and normal sales exception), among other requirements, and the company has documented its intent to apply this exception. ConocoPhillips generally applies this exception to eligible purchase and sales contracts; however, the company may elect not to apply this exception (e.g., when another derivative instrument will be used to mitigate the risk of the purchase or sale contract but hedge accounting will not be applied). When this occurs, both the purchase or sales contract and the derivative contract mitigating the resulting risk will be recorded on the balance sheet at fair value in accordance with the preceding paragraphs.

Interest Rate Derivative Contracts — On August 30, 2002, the company obtained a number of fixed-to-floating and floating-to-fixed interest rate swaps from the merger. ConocoPhillips designated these swaps as hedges, but by December 31, 2002, all of the fixed-to-floating rate swaps and a portion of the floating-to-fixed rate swaps had been terminated. The floating-to-fixed interest rate swaps still open at December 31, 2002, are as follows:

	Millions of Dollars	
	Notional Amount	Fair Value
Cash Flow Hedges		
Maturing 2006	$166	(19)
Maturing in less than one year	500	(3)

ConocoPhillips generally reports gains, losses, and ineffectiveness from interest rate derivatives on the statement of operations in interest and debt expense; however, when interest rate derivatives are used to hedge the interest component of a lease, the resulting gains and losses are reported on the statement of operations in production and operating expense. No portion of the gain or loss from the swaps designated as interest rate hedges has been excluded from the assessment of hedge ineffectiveness, which was immaterial for the period from August 30 to December 31, 2002. In accordance with the hedge accounting provisions of Statement No. 133, any realized gains or losses from these derivative hedging instruments will be recognized as income or expense in future periods concurrent with the forecasted transactions. The company expects the amount of net unrealized losses from interest rate hedges in accumulated other comprehensive loss at December 31, 2002, that will be reclassified to earnings during the next 12 months to be immaterial.

Currency Exchange Rate Derivative Contracts — During the third quarter of 2001, ConocoPhillips used hedge accounting to record the results of using a forward exchange contract to hedge the exposure to fluctuations in the exchange rate between the U.S. dollar and Brazilian real, resulting from a firm commitment to pay reals to acquire an exploratory lease. The hedge was closed in August 2001, upon payment of the lease bonus. Results from the hedge appear in accumulated other comprehensive loss on the balance sheet and will be reclassified into earnings concurrent with the amortization or write-down of the lease bonus, but no portion of this amount is expected to be reclassified during 2003. No component of the hedge results was excluded from the assessment of hedge effectiveness, and no gain or loss was recorded in the statement of operations from hedge ineffectiveness.

After the merger, the company has foreign currency exchange rate risk resulting from operations in over 40 countries. ConocoPhillips does not comprehensively hedge the exposure to currency rate changes, although the company may choose to selectively hedge exposures to foreign currency rate risk. Examples include firm commitments for capital projects, certain local currency tax payments and dividends, and cash returns from net investments in foreign affiliates to be remitted within the coming year. Hedge accounting is not currently being used for any of the company's foreign currency derivatives.

Commodity Derivative Contracts — ConocoPhillips operates in the worldwide crude oil, refined product, natural gas, natural gas liquids, and electric power markets and is exposed to fluctuations in the prices for these commodities. These fluctuations can affect the company's revenues as well as the cost of operating, investing, and financing activities. Generally, ConocoPhillips' policy is to remain exposed to market prices of commodity purchases and sales; however, executive management may elect to use derivative instruments to establish longer-term positions to hedge the price risk of the company's equity crude oil and natural gas production, as well as refinery margins.

The ConocoPhillips Commercial Group use futures, forwards, swaps, and options in various markets to optimize the value of the company's supply chain, which may move the company's risk profile away from market average prices to accomplish the following objectives:

- Balance physical systems. In addition to cash settlement prior to contract expiration, exchange traded futures contracts may also be settled by physical delivery of the commodity, providing another source of supply to meet the company's refinery requirements or marketing demand;
- Meet customer needs. Consistent with the company's policy to generally remain exposed to market prices, the company uses swap contracts to convert fixed-price sales contracts, which are often requested by natural gas and refined product consumers, to a floating market price;
- Manage the risk to the company's cash flows from price exposures on specific crude oil, natural gas, refined product and electric power transactions; and
- Enable the company to use the market knowledge gained from these activities to do a limited amount of trading not directly related to the company's physical business. For the 12 months ended December 31, 2002 and 2001, the gains or losses from this activity were not material to the company's cash flows or income from continuing operations.

At December 31, 2002, ConocoPhillips was not using hedge accounting for commodity derivative contracts; however, during the first half of 2002, the company did use hedge accounting for West Texas Intermediate (WTI) crude oil futures designated as fair-value hedges of firm commitments to sell WTI crude oil at Cushing, Oklahoma. The changes in the fair values of the futures and firm commitments have been recognized in income. No component of the futures gain or loss was excluded from the assessment of hedge effectiveness, and the amount recognized in earnings during the year from ineffectiveness was immaterial.

Credit Risk

The company's financial instruments that are potentially exposed to concentrations of credit risk consist primarily of cash equivalents, over-the-counter derivative contracts, and trade receivables. ConocoPhillips' cash equivalents, which are placed in high-quality money market funds and time deposits with major international banks and financial institutions, are generally not maintained at levels material to the company's financial position. The credit risk from the company's over-the-counter derivative contracts, such as forwards and swaps, derives from the counterparty to the transaction, typically a major bank or financial institution. ConocoPhillips closely monitors these credit exposures against predetermined credit limits, including the continual exposure adjustments that result from market movements. Individual counterparty exposure is managed within these limits, and includes the use of cash-call margins when appropriate, thereby reducing the risk of significant non-performance. ConocoPhillips also uses futures contracts, but futures have a negligible credit risk because they are traded on the New York Mercantile Exchange or the International Petroleum Exchange of London Limited.

The company's trade receivables result primarily from its petroleum operations and reflect a broad national and international customer base, which limits the company's exposure to concentrations of credit risk. The majority of these receivables have payment terms of 30 days or less, and the company continually monitors this exposure and the creditworthiness of the counterparties. ConocoPhillips does not generally require collateral to limit the exposure to loss; however, ConocoPhillips will sometimes use letters of credit, prepayments, and master netting arrangements to mitigate credit risk with counterparties that both buy from and sell to the company, as these agreements permit the amounts owed by ConocoPhillips to be offset against amounts due to the company.

Fair Values of Financial Instruments

The company used the following methods and assumptions to estimate the fair value of its financial instruments:

Cash and cash equivalents: The carrying amount reported on the balance sheet approximates fair value.

Accounts and notes receivable: The carrying amount reported on the balance sheet approximates fair value.

Debt and mandatorily redeemable preferred securities: The carrying amount of the company's floating-rate debt approximates fair value. The fair value of the fixed-rate debt and mandatorily redeemable preferred securities is estimated based on quoted market prices.

Swaps: Fair value is estimated based on forward market prices and approximates the net gains and losses that would have been realized if the contracts had been closed out at year-end. When forward market prices are not available, they are estimated using the forward prices of a similar commodity with adjustments for differences in quality or location.

Futures: Fair values are based on quoted market prices obtained from the New York Mercantile Exchange or the International Petroleum Exchange of London Limited.

Forward-exchange contracts: Fair value is estimated by comparing the contract rate to the forward rate in effect on December 31 and approximates the net gains and losses that would have been realized if the contracts had been closed out at year-end.

Certain company financial instruments at December 31 were:

	Millions of Dollars			
	Carrying Amount		Fair Value	
	2002	2001	**2002**	2001
Financial assets				
Foreign currency derivatives	**$ 17**	—	**17**	—
Commodity derivatives	**180**	5	**180**	5
Financial liabilities				
Total debt, excluding capital leases	**19,743**	8,654	**20,844**	9,175
Mandatorily redeemable other minority interests and preferred securities	**491**	650	**516**	662
Interest rate derivatives	**22**	—	**22**	—
Foreign currency derivatives	**4**	—	**4**	—
Commodity derivatives	**180**	7	**180**	7

Note 17 — Preferred Stock and Other Minority Interests

Company-Obligated Mandatorily Redeemable Preferred Securities of Phillips 66 Capital Trusts

During 1996 and 1997, the company formed two statutory business trusts, Phillips 66 Capital I (Trust I) and Phillips 66 Capital II (Trust II), in which the company owns all common stock. The Trusts were created for the sole purpose of issuing securities and investing the proceeds thereof in an equivalent amount of subordinated debt securities of ConocoPhillips. ConocoPhillips established the two trusts to raise funds for general corporate purposes.

On May 31, 2002, ConocoPhillips redeemed all of its outstanding 8.24% Junior Subordinated Deferrable Interest Debentures due 2036 held by Trust I. This triggered the redemption of $300 million of Trust I's 8.24% Trust Originated Preferred Securities at par value, $25 per share. An extraordinary loss of $8 million before-tax, $6 million after-tax, was incurred during the second quarter of 2002 as a result of the redemption.

Trust II has outstanding $350 million of 8% Capital Securities (Capital Securities). The sole asset of Trust II is $361 million of the company's 8% Junior Subordinated Deferrable Interest Debentures due 2037 (Subordinated Debt Securities II) purchased by Trust II on January 17, 1997. The Subordinated Debt Securities II are due January 15, 2037, and are redeemable in whole, or in part, at the option of ConocoPhillips, on or after January 15, 2007, at a redemption price of $1,000 per share, plus accrued and unpaid interest.

Subordinated Debt Securities II are unsecured obligations of ConocoPhillips, equal in right of payment but subordinate and junior in right of payment to all present and future senior indebtedness of ConocoPhillips.

The subordinated debt securities and related income statement effects are eliminated in the company's consolidated financial statements. When the company redeems the Subordinated Debt Securities II, Trust II is required to apply all redemption proceeds to the immediate redemption of the Capital Securities. ConocoPhillips fully and unconditionally guarantees Trust II's obligations under the Capital Securities.

Other Mandatorily Redeemable Minority Interests

The minority limited partner in Conoco Corporate Holdings L.P. is entitled to a cumulative annual 7.86 percent priority return on its investment. The net minority interest in Conoco Corporate

Holdings held by the limited partner was $141 million at December 31, 2002, and is mandatorily redeemable in 2019 or callable without penalty beginning in the fourth quarter of 2004.

Other Minority Interests

The minority interest owner in Ashford Energy Capital S.A. is entitled to a cumulative annual preferred return on its investment, based on three-month LIBOR rates plus 1.27 percent. The preferred return at December 31, 2002, was 2.70 percent. At December 31, 2002, the minority interest was $504 million.

In January 2003, the FASB issued Interpretation No. 46, "Consolidation of Variable Interest Entities," and later in 2003, the FASB is expected to issue SFAS No. 149, "Accounting for Certain Financial Instruments with Characteristics of Liabilities and Equity." The company is evaluating these new pronouncements to determine whether the above items currently presented in the mezzanine section of the balance sheet will be required to be presented as debt or equity on the balance sheet. See Note 27 — New Accounting Standards and Note 28 — Variable Interest Entities for more information.

Preferred Stock

ConocoPhillips has 500 million shares of preferred stock authorized, par value $.01 per share, none of which was issued or outstanding at December 31, 2002.

Note 18 — Preferred Share Purchase Rights

ConocoPhillips' Board of Directors has authorized and declared a dividend of one preferred share purchase right for each common share outstanding, and has authorized and directed the issuance of one right per common share for any newly issued shares. The rights, which expire June 30, 2012, will be exercisable only if a person or group acquires 15 percent or more of the company's common stock or commences a tender offer that would result in ownership of 15 percent or more of the common stock. Each right would entitle stockholders to buy one one-hundredth of a share of preferred stock at an exercise price of $300. In addition, the rights enable holders to either acquire additional shares of ConocoPhillips common stock or purchase the stock of an acquiring company at a discount, depending on specific circumstances. The company may redeem the rights in whole, but not in part, for one cent per right.

Note 19 — Non-Mineral Leases

The company leases ocean transport vessels, railroad tank cars, corporate aircraft, service stations, computers, office buildings and other facilities and equipment. Certain leases include escalation clauses for adjusting rentals to reflect changes in price indices, as well as renewal options and/or options to purchase the leased property for the fair market value at the end of the lease term. There are no significant restrictions on ConocoPhillips imposed by the leasing agreements in regards to dividends, asset dispositions or borrowing ability. Leased assets under capital leases were not significant in any period presented.

ConocoPhillips has leasing arrangements with several special purpose entities (SPEs) that are third-party trusts established by a trustee and funded by financial institutions. Other than the leasing arrangement, ConocoPhillips has no other direct or indirect relationship with the trusts or their investors. Each SPE from which ConocoPhillips leases assets is funded by at least 3 percent substantive third-party residual equity capital investment, which is at-risk during the entire term of the lease. ConocoPhillips does have various purchase options to acquire the leased assets from the SPEs at the end of the lease term, but those purchase options are not required to be exercised by ConocoPhillips. See Note 28 — Variable Interest Entities, for a discussion of how the accounting for certain leasing arrangements with SPEs may change in 2003.

In connection with the committed plan to sell a major portion of the company's owned retail stores, the company plans to exercise purchase option provisions of various operating leases during 2003 involving approximately 900 store sites and two office buildings. Depending upon the timing of when the company adopts FASB Interpretation No. 46, "Consolidation of Variable Interest Entities," and the determination of whether or not the lessor entities in these leases are variable interest entities, some or all of these lessor entities could become consolidated subsidiaries of the company prior to the exercise of the purchase options. See Note 27 — New Accounting Standards, and Note 28 — Variable Interest Entities, for additional information on FASB Interpretation No. 46.

At December 31, 2002, future minimum rental payments due under non-cancelable leases, including those associated with discontinued operations, were:

	Millions of Dollars
2003	$ 649
2004	546
2005	479
2006	425
2007	367
Remaining years	1,635
Total	4,101
Less income from subleases	641*
Net minimum operating lease payments	$3,460

**Includes $164 million related to railroad cars subleased to CPChem, a related party.*

The above amounts exclude guaranteed residual value payments, including those associated with discontinued operations, totaling $196 million in 2003, $219 million in 2004, $827 million in 2005, $145 million in 2006, and $434 million in the remaining years, due at the end of lease terms, which would be reduced by the fair market value of the leased assets returned. See Note 4 — Discontinued Operations regarding the company's commitment to exit certain retail sites and the related accrual for probable deficiencies under the residual value guarantees.

The company also expects to recognize probable guaranteed residual value deficiencies associated with certain retail sites included in continuing operations. The company plans to exercise its purchase options under these leases in 2003, resulting in the recognition of a $142 million, $92 million after-tax, loss.

ConocoPhillips has agreements with a shipping company for the long-term charter of five crude oil tankers that are currently under construction. The charters will be accounted for as operating leases upon delivery, which is expected in the third and fourth quarters of 2003. If the completed tankers are not delivered to ConocoPhillips before specified dates in 2004, the chartering commitments are cancelable by ConocoPhillips. Upon delivery, the base term of the charter agreements is 12 years, with certain renewal options by ConocoPhillips. ConocoPhillips has options to cancel the charter agreements at any time, including during construction or after delivery. After delivery, if ConocoPhillips were to exercise its cancellation options, the company's maximum commitment for the five tankers together would be $92 million. If ConocoPhillips does not exercise its cancellation options, the total operating lease commitment over the 12-year term for the five tankers would be $383 million on an estimated bareboat basis.

Operating lease rental expense for the years ended December 31 was:

	Millions of Dollars		
	2002	2001	2000
Total rentals*	**$541**	271	128
Less sublease rentals	**21**	22	2
	$520	249	126

**Includes $12 million of contingent rentals in 2002. Contingent rentals in 2001 and 2000 were not significant.*

Note 20 — Employee Benefit Plans

Pension and Postretirement Plans

An analysis of the projected benefit obligations for the company's pension plans and accumulated benefit obligations for its postretirement health and life insurance plans follows:

	Millions of Dollars					
	Pension Benefits				Other Benefits	
	2002		2001		**2002**	2001
	U.S.	**Int'l.**	U.S.	Int'l.		
Change in Benefit Obligation						
Benefit obligation at January 1	**$1,432**	**417**	991	386	**239**	140
Service cost	**75**	**32**	40	15	**9**	4
Interest cost	**133**	**48**	82	24	**31**	11
Plan participant contributions	**—**	**2**	—	1	**15**	11
Plan amendments	**(12)**	**—**	6	—	**133**	21
Actuarial (gain) loss	**205**	**(21)**	161	8	**31**	14
Acquisitions	**1,349**	**908**	277	—	**509**	68
Benefits paid	**(159)**	**(23)**	(131)	(12)	**(47)**	(31)
Curtailment	**(36)**	**—**	—	(2)	**(4)**	—
Recognition of termination benefits	**92**	**3**	6	5	**3**	1
Foreign currency exchange rate change	**—**	**135**	—	(8)	**—**	—
Benefit obligation at December 31	**$3,079**	**1,501**	1,432	417	**919**	239
Accumulated benefit obligation portion of above at December 31	**$2,455**	**1,325**	1,121	345		
Change in Fair Value of Plan Assets						
Fair value of plan assets at January 1	**$ 732**	**381**	696	401	**21**	20
Actual return on plan assets	**(85)**	**(74)**	(91)	(19)	**(5)**	2
Acquisitions	**600**	**594**	166	—	**—**	4
Company contributions	**145**	**39**	92	18	**27**	15
Plan participant contributions	**—**	**2**	—	1	**15**	11
Benefits paid	**(159)**	**(21)**	(131)	(12)	**(47)**	(31)
Foreign currency exchange rate change	**—**	**106**	—	(8)	**—**	—
Fair value of plan assets at December 31	**$1,233**	**1,027**	732	381	**11**	21

	Millions of Dollars					
	Pension Benefits				Other Benefits	
	2002		2001		**2002**	2001
	U.S.	**Int'l.**	U.S.	Int'l.		
Funded Status						
Excess obligation	**$(1,846)**	**(474)**	(700)	(36)	**(908)**	(218)
Unrecognized net actuarial loss	**697**	**171**	418	61	**60**	30
Unrecognized prior service cost	**30**	**5**	57	7	**131**	18
Total recognized amount in the consolidated balance sheet	**$(1,119)**	**(298)**	(225)	32	**(717)**	(170)
Components of above amount:						
Prepaid benefit cost	**$ —**	**52**	5	37	**—**	—
Accrued benefit liability	**(1,484)**	**(400)**	(501)	(15)	**(717)**	(170)
Intangible asset	**43**	**3**	57	4	**—**	—
Accumulated other comprehensive loss	**322**	**47**	214	6	**—**	—
Total recognized	**$(1,119)**	**(298)**	(225)	32	**(717)**	(170)
Weighted-Average Assumptions as of December 31						
Discount rate	**6.75%**	**5.85**	7.25	6.30	**6.75**	7.25
Expected return on plan assets	**7.05**	**7.45**	8.70	7.60	**5.50**	5.20
Rate of compensation increase	**4.00**	**3.80**	4.00	3.75	**4.00**	4.00

Pension plan funds are invested in a diversified portfolio of assets. Approximately $198 million held in a participating annuity contract is not available for meeting benefit obligations in the near term. At December 31, 2002, approximately 4,300 shares of company stock were included in plan assets. At December 31, 2001, no company stock was included in plan assets. The company's funding policy for U.S. plans is to contribute at least the minimum required by the Employee Retirement Income Security Act of 1974. Contributions to foreign plans are dependent upon local laws and tax regulations. In 2003, the company expects to contribute approximately $340 million to its domestic qualified pension plans and $50 million to its international qualified pension plans.

The funded status of the plans was impacted in 2002 by changes in assumptions used to calculate plan liabilities, the merger of Conoco and Phillips, and negative asset performance.

During 2002, the company recorded charges to other comprehensive loss totaling $149 million ($93 million net of tax), resulting in accumulated other comprehensive loss due to minimum pension liability adjustments at December 31, 2002, of $369 million ($236 million net of tax).

	Millions of Dollars								
	Pension Benefits						Other Benefits		
	2002		2001		2000		**2002**	2001	2000
	U.S.	**Int'l.**	U.S.	Int'l.	U.S.	Int'l.			
Components of Net Periodic Benefit Cost									
Service cost	**$ 75**	**32**	40	15	32	16	**9**	4	2
Interest cost	**133**	**48**	82	24	75	23	**31**	11	9
Expected return on plan assets	**(73)**	**(49)**	(74)	(30)	(80)	(29)	**(1)**	(1)	(1)
Amortization of prior service cost	**5**	**2**	6	1	5	1	**8**	(1)	(3)
Recognized net actuarial loss (gain)	**48**	**7**	16	—	(5)	—	**3**	2	1
Amortization of net asset	**—**	**—**	—	(1)	(7)	—	**—**	—	—
Net periodic benefit cost	**$188**	**40**	70	9	20	11	**50**	15	8

The company recorded curtailment losses of $23 million and $1 million in 2002 and 2000, respectively, and a curtailment gain of $2 million in 2001. The company recorded settlement losses of $10 million in 2001.

In determining net pension and other postretirement benefit costs, ConocoPhillips has elected to amortize net gains and losses on a straight-line basis over 10 years. Prior service cost is amortized on a straight-line basis over the average remaining service period of employees expected to receive benefits under the plan.

For the company's tax-qualified pension plans with projected benefit obligations in excess of plan assets, the projected benefit obligation, the accumulated benefit obligation, and the fair value of plan assets were $4,288 million, $3,542 million, and $2,259 million at December 31, 2002, respectively, and $1,519 million, $1,211 million, and $886 million at December 31, 2001, respectively.

For the company's unfunded non-qualified supplemental key employee pension plans, the projected benefit obligation and the accumulated benefit obligation were $260 million and $206 million, respectively, at December 31, 2002, and were $109 million and $76 million, respectively, at December 31, 2001.

The company has multiple non-pension postretirement benefit plans for health and life insurance. The health care plans are contributory, with participant and company contributions adjusted annually; the life insurance plans are non-contributory. For most groups of retirees, any increase in the annual health care escalation rate above 4.5 percent is borne by the participant. The weighted-average health care cost trend rate for those participants not subject to the cap is assumed to decrease gradually from 10 percent in 2003 to 5 percent in 2009.

The assumed health care cost trend rate impacts the amounts reported. A one-percentage-point change in the assumed health care cost trend rate would have the following effects on the 2002 amounts:

	Millions of Dollars	
	One-Percentage-Point	
	Increase	Decrease
Effect on total of service and interest cost components	$—	—
Effect on the postretirement benefit obligation	3	3

Defined Contribution Plans

At December 31, 2002, most employees (excluding retail service station employees) were eligible to participate in either the company-sponsored Thrift Plan of Phillips Petroleum Company, the Tosco Corporation Capital Accumulation Plan, or the Thrift Plan for Employees of Conoco Inc. Employees could contribute a portion of their salaries to various investment funds, including a company stock fund, a percentage of which was matched by the company. In addition, eligible participants in the Tosco Corporation Capital Accumulation Plan could receive an additional company contribution in lieu of pension plan benefits. Company contributions charged to expense in total for all three plans were $40 million in 2002, and $14 million in 2001 and $6 million in 2000.

The company's Long-Term Stock Savings Plan (LTSSP) was a leveraged employee stock ownership plan. Prior to January 1, 2003, employees eligible for the Thrift Plan of Phillips Petroleum Company could also elect to participate in the LTSSP by contributing 1 percent of their salaries and receiving an allocation of shares of common stock proportionate to their contributions. On January 1, 2003, the Thrift Plan of Phillips Petroleum Company and the Tosco Corporation Capital Accumulation Plan were merged into the LTSSP and the name was changed to the ConocoPhillips Savings Plan (and the LTSSP became known as the Stock Savings Feature within that plan). The ConocoPhillips Savings Plan replaced most features available under the Thrift Plan of Phillips Petroleum Company and the Tosco Corporation Capital Accumulation Plan. In addition to participating in the Thrift Plan for Employees of Conoco Inc., on January 1, 2003, heritage Conoco employees became eligible to participate in the Stock Savings Feature of the ConocoPhillips Savings Plan.

In 1990, the LTSSP borrowed funds that were used to purchase previously unissued shares of company common stock. Since the company guarantees the LTSSP's borrowings, the unpaid balance is reported as a liability of the company and unearned compensation is shown as a reduction of common stockholders' equity. Dividends on all shares are charged against retained earnings. The debt is serviced by the LTSSP from company contributions and dividends received on certain shares of common stock held by the plan, including all unallocated shares. The shares held by the LTSSP are released for allocation to participant accounts based on debt service payments on LTSSP borrowings. In addition, during the period from 2003 through 2007, when no debt principal payments are scheduled to occur, the company has committed to make direct contributions of stock to the LTSSP, or make prepayments on LTSSP borrowings, to ensure a certain minimum level of stock allocation to participant accounts.

The company recognizes interest expense as incurred and compensation expense based on the fair market value of the stock contributed or on the cost of the unallocated shares released, using the shares-allocated method. The company recognized total LTSSP expense of $39 million, $33 million and $40 million in 2002, 2001 and 2000, respectively, all of which was compensation expense. In 2002, 2001 and 2000, respectively, the company made cash contributions to the LTSSP of $2 million, $17 million and $23 million. In 2002, 2001 and 2000, the company contributed 771,479 shares, 292,857 shares and 508,828 shares, respectively, of company common stock from the Compensation and Benefits Trust. The shares had a fair market value of $41 million, $17 million and $24 million, respectively. Dividends used to service debt were $28 million, $28 million and $32 million in 2002, 2001 and 2000, respectively.

These dividends reduced the amount of expense recognized each period. Interest incurred on the LTSSP debt in 2002, 2001 and 2000 was $7 million, $17 million and $26 million, respectively.

The total LTSSP shares as of December 31 were:

	2002	2001
Unallocated shares	**7,717,710**	8,379,924
Allocated shares	**14,925,443**	14,794,203
Total LTSSP shares	**22,643,153**	23,174,127

The fair value of unallocated shares at December 31, 2002, and 2001, was $373 million and $505 million, respectively.

Stock-Based Compensation Plans

Under the company's Omnibus Securities Plan approved by shareholders in 1993, stock options and stock awards for certain employees were authorized for up to eight-tenths of 1 percent (0.8 percent) of the total outstanding shares as of December 31 of the year preceding the awards. Any shares not issued in the current year were available for future grant. Upon the adoption of the 2002 Omnibus Securities Plan discussed below, the number of shares available for issuance under the Omnibus Securities Plan was limited to 700,000. The term of the Omnibus Securities Plan ended on December 31, 2002.

In 2001, shareholders approved the 2002 Omnibus Securities Plan, which has a term of five years, from January 1, 2002, through December 31, 2006, and which is authorized to issue approximately 18,000,000 shares of company common stock. The two plans also provided for non-stock-based awards.

Shares of company stock awarded under both plans were:

	2002	2001	2000
Shares	**1,090,082**	237,849	319,726
Weighted-average fair value	**$57.84**	56.23	46.98

Stock options granted under provisions of the plans and earlier plans permit purchase of the company's common stock at exercise prices equivalent to the average market price of the stock on the date the options were granted. The options have terms of 10 years and normally become exercisable in increments of up to one-third on each anniversary date following the date of grant. Stock Appreciation Rights (SARs) may, from time to time, be affixed to the options. Options exercised in the form of SARs permit the holder to receive stock, or a combination of cash and stock, subject to a declining cap on the exercise price.

The merger was a change-in-control event that resulted in a lapsing of restrictions on, and payout of, stock and stock option awards under the plans. ConocoPhillips offered to exchange certain stock awards under the plans with new awards in the form of restricted stock units. These new restricted stock units were converted, at the time of the merger, into awards based on the same number of shares of ConocoPhillips common stock.

Conoco had several stock-based compensation plans that were assumed in the merger: the 1998 Stock and Performance Incentive Plan; the 1998 Key Employee Stock Performance Plan; the 1998 Global Performance Sharing Plan; and the 2001 Global Performance Sharing Plan. Upon the merger, outstanding stock options under these plans were converted to ConocoPhillips stock options at the merger exchange ratio of 0.4677.

The Conoco plans award stock options at exercise prices equivalent to the average market price of the stock on the date the option was granted. Awards have option terms of 10 years and become exercisable based on various formulas, including those that become exercisable one year from date of grant, and those that become exercisable in increments of one-third on each anniversary date following date of grant. In total, there were 16 million shares of company stock at December 31, 2002, available for issuance under the Conoco plans.

Stock-based compensation expense recognized by ConocoPhillips in connection with all the plans discussed above was $60 million, $21 million and $23 million in 2002, 2001 and 2000, respectively.

Beginning in 2003, ConocoPhillips has elected to use the fair-value accounting method provided for under SFAS No. 123, "Accounting for Stock-Based Compensation." The company will use the prospective transition method provided under SFAS 123, applying the fair-value accounting method and recognizing compensation expense for all stock options granted, modified or settled after December 31, 2002.

Employee stock options granted prior to 2003 will continue to be accounted for under APB No. 25, "Accounting for Stock Issued to Employees," and related Interpretations. Because the exercise price of ConocoPhillips employee stock options equals the market price of the underlying stock on the date of grant, no compensation expense is generally recognized under APB No. 25. The following table displays pro forma information as if the provisions of SFAS No. 123 had been applied to employee stock options granted since January 1, 1996:

	2002	2001	2000
Pro forma net income (loss) in millions	**$ (358)**	1,644	1,850
Pro forma basic income (loss) per share	**(.74)**	5.61	7.27
Pro forma diluted income (loss) per share	**(.74)**	5.57	7.21
Assumptions used			
Risk-free interest rate	**4.1%**	4.5	5.9
Dividend yield	**3.0%**	2.5	2.5
Volatility factor	**26.2%**	27.0	26.0
Average grant date fair value of options	**$11.67**	23.19	16.00
Expected life (years)	**6**	5	5

In August 2002, ConocoPhillips issued 23.3 million vested stock options to replace unexercised Conoco stock options at the time of the merger. These options had a weighted-average exercise price of $47.65 per option, and a Black-Scholes option-pricing model value of $16.50 per option. In September 2001, ConocoPhillips issued 4.7 million vested stock options to replace unexercised Tosco stock options at the time of the acquisition. These options had a weighted-average exercise price of $23.15 per option, and a Black-Scholes option-pricing model value of $32.51 per option.

A summary of ConocoPhillips' stock option activity follows:

	Options	Weighted-Average Exercise Price
Outstanding at December 31, 1999	9,844,524	$39.84
Granted	1,299,500	61.85
Exercised	(1,223,779)	30.79
Forfeited	(57,278)	47.06
Outstanding at December 31, 2000	9,862,967	$43.82
Granted (including Tosco exchange)	9,038,571	38.81
Exercised	(2,373,062)	22.36
Forfeited	(96,126)	60.41
Outstanding at December 31, 2001	16,432,350	$44.06
Granted (including the merger)	**28,830,903**	**48.11**
Exercised	**(2,032,232)**	**24.66**
Forfeited	**(124,416)**	**57.78**
Outstanding at December 31, 2002	**43,106,605**	**$47.65**

Outstanding at December 31, 2002

		Weighted-Average	
Exercise Prices	Options	Remaining Lives	Exercise Price
$ 9.04 to $31.44	**5,067,979**	**2.18 years**	**$25.06**
$31.52 to $44.91	**6,384,431**	**4.29 years**	**39.88**
$45.75 to $66.72	**31,654,195**	**7.67 years**	**52.83**

Exercisable at December 31

	Exercise Prices	Options	Weighted-Average Exercise Price
2002	**$ 9.04 to $31.44**	**5,067,979**	**$25.06**
	$31.52 to $44.91	**6,384,431**	**39.88**
	$45.75 to $66.72	**21,614,181**	**52.17**
2001	$ 9.04 to $31.44	3,056,009	$22.67
	$31.52 to $44.91	3,075,354	38.06
	$45.75 to $64.43	3,525,616	48.32
2000	$22.57 to $31.44	1,754,047	$29.42
	$32.25 to $44.91	1,674,129	37.49
	$45.75 to $62.57	2,029,352	46.46

Compensation and Benefits Trust (CBT)

The CBT is an irrevocable grantor trust, administered by an independent trustee and designed to acquire, hold and distribute shares of the company's common stock to fund certain future compensation and benefit obligations of the company. The CBT does not increase or alter the amount of benefits or compensation that will be paid under existing plans, but offers the company enhanced financial flexibility in providing the funding requirements of those plans. ConocoPhillips also has flexibility in determining the timing of distributions of shares from the CBT to fund compensation and benefits, subject to a minimum distribution schedule. The trustee votes shares held by the CBT in accordance with voting directions from eligible employees, as specified in a trust agreement with the trustee.

The company sold 29.2 million shares of previously unissued company common stock to the CBT in 1995 for $37 million of cash, previously contributed to the CBT by ConocoPhillips, and a promissory note from the CBT to ConocoPhillips of $952 million. The CBT is consolidated by ConocoPhillips, therefore the cash contribution and promissory note are eliminated in consolidation. Shares held by the CBT are valued at cost and do not affect earnings per share or total common stockholders' equity until after they are transferred out of the CBT. In 2002 and 2001, shares transferred out of the CBT were 771,479 and 292,857, respectively. At December 31, 2002, 26.8 million shares remained in the CBT. All shares are required to be transferred out of the CBT by January 1, 2021.

Note 21 — Taxes

Taxes charged to income from continuing operations were:

	Millions of Dollars		
	2002	2001	2000
Taxes Other Than Income Taxes			
Excise	**$6,246**	2,177	1,781
Property	**244**	148	108
Production	**303**	328	278
Payroll	**99**	54	50
Environmental	**5**	14	12
Other	**40**	19	13
	$6,937	2,740	2,242
Income Taxes			
Federal			
Current	**$ 71**	133	470
Deferred	**56**	426	224
Foreign			
Current	**1,188**	842	965
Deferred	**114**	126	127
State and local			
Current	**57**	97	100
Deferred	**(36)**	20	14
	$1,450	1,644	1,900

Deferred income taxes reflect the net tax effect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for tax purposes. Major components of deferred tax liabilities and assets at December 31 were:

	Millions of Dollars	
	2002	2001
Deferred Tax Liabilities		
Properties, plants and equipment, and intangibles	**$10,147**	4,750
Investment in joint ventures	**1,013**	522
Inventory	**385**	212
Other	**144**	74
Total deferred tax liabilities	**11,689**	5,558
Deferred Tax Assets		
Benefit plan accruals	**1,304**	450
Accrued dismantlement, removal and environmental costs	**724**	452
Deferred state income tax	**201**	164
Other financial accruals and deferrals	**311**	182
Alternative minimum tax carryforwards	**421**	180
Operating loss and credit carryforwards	**650**	310
Other	**394**	107
Total deferred tax assets	**4,005**	1,845
Less valuation allowance	**608**	263
Net deferred tax assets	**3,397**	1,582
Net deferred tax liabilities	**$ 8,292**	3,976

Current assets, long-term assets, current liabilities and long-term liabilities included deferred taxes of $68 million, $41 million, $40 million and $8,361 million, respectively, at December 31, 2002, and $47 million, $9 million, $17 million and $4,015 million, respectively, at December 31, 2001.

The company has operating loss and credit carryovers in multiple taxing jurisdictions. These attributes generally expire between 2003 and 2009 with some carryovers, including the alternative minimum tax, having indefinite carryforward periods.

Valuation allowances have been established for certain operating loss and credit carryforwards that reduce deferred tax assets to an amount that will, more likely than not, be realized. Uncertainties that may affect the realization of these assets include tax law changes and the future level of product prices and costs. Based on the company's historical taxable income, its expectations for the future, and available tax-planning strategies, management expects that the net deferred tax assets will be realized as offsets to reversing deferred tax liabilities and as offsets to the tax consequences of future taxable income.

The Conoco purchase price allocation for the merger resulted in net deferred tax liabilities of $4,073 million. Included in this amount is a valuation allowance for certain deferred tax assets of $251 million, for which subsequently recognized tax benefits, if any, will be allocated to goodwill.

At December 31, 2002, and December 31, 2001, income considered to be permanently reinvested in certain foreign subsidiaries and foreign corporate joint ventures totaled approximately $569 million and $247 million, respectively. Deferred income taxes have not been provided on this income, as the company does not plan to initiate any action that would require the payment of income taxes. It is not practicable to estimate the amount of additional tax that might be payable on this foreign income if distributed.

The amounts of U.S. and foreign income from continuing operations before income taxes, with a reconciliation of tax at the federal statutory rate with the provision for income taxes, were:

	Millions of Dollars			Percent of Pretax Income		
	2002	2001	2000	**2002**	2001	2000
Income from continuing operations before income taxes						
United States	**$ 628**	2,080	2,041	**29.0%**	63.9	54.4
Foreign	**1,536**	1,175	1,707	**71.0**	36.1	45.6
	$2,164	3,255	3,748	**100.0%**	100.0	100.0
Federal statutory income tax	**$ 757**	1,139	1,312	**35.0%**	35.0	35.0
Foreign taxes in excess of federal statutory rate	**680**	515	572	**31.4**	15.8	15.3
Domestic tax credits	**(77)**	(84)	(53)	**(3.6)**	(2.6)	(1.4)
Write-off of acquired in-process research and development costs	**86**	—	—	**4.0**	—	—
State income tax	**14**	76	74	**.6**	2.3	2.0
Other	**(10)**	(2)	(5)	**(.4)**	—	(.2)
	$1,450	1,644	1,900	**67.0%**	50.5	50.7

Note 22 — Other Comprehensive Income (Loss)

The components and allocated tax effects of other comprehensive income (loss) follow:

	Millions of Dollars		
	Before-Tax	Tax Expense (Benefit)	After-Tax
2002			
Minimum pension liability adjustment	**$(149)**	**(56)**	**(93)**
Unrealized loss on securities	**(3)**	**—**	**(3)**
Foreign currency translation adjustments	**223**	**41**	**182**
Hedging activities	**(1)**	**—**	**(1)**
Equity affiliates:			
Foreign currency translation	**40**	**—**	**40**
Derivatives related	**(34)**	**—**	**(34)**
Other comprehensive income	**$ 76**	**(15)**	**91**
2001			
Minimum pension liability adjustment	$(220)	(77)	(143)
Unrealized loss on securities	(3)	(1)	(2)
Foreign currency translation adjustments	(14)	—	(14)
Hedging activities	(4)	—	(4)
Equity affiliates:			
Foreign currency translation	(3)	—	(3)
Derivatives related	17	6	11
Other comprehensive loss	$(227)	(72)	(155)
2000			
Unrealized loss on securities	$ (2)	(1)	(1)
Foreign currency translation adjustments	(53)	—	(53)
Equity affiliates:			
Foreign currency translation	(15)	—	(15)
Other comprehensive loss	$ (70)	(1)	(69)

See Note 20 — Employee Benefit Plans for more information on the minimum pension liability adjustment.

Unrealized gains on securities relate to available-for-sale securities held by irrevocable grantor trusts that fund certain of the company's domestic, non-qualified supplemental key employee pension plans.

Deferred taxes have not been provided on temporary differences related to foreign currency translation adjustments for investments in certain foreign subsidiaries and foreign corporate joint ventures that are essentially permanent in duration.

Accumulated other comprehensive loss in the equity section of the balance sheet included:

	Millions of Dollars	
	2002	2001
Minimum pension liability adjustment	**$(236)**	(143)
Foreign currency translation adjustments	**98**	(84)
Unrealized gain on securities	**1**	4
Deferred net hedging loss	**(5)**	(4)
Equity affiliates:		
Foreign currency translation	**1**	(39)
Derivatives related	**(23)**	11
Accumulated other comprehensive loss	**$(164)**	(255)

Note 23 — Cash Flow Information

	Millions of Dollars		
	2002	2001	2000
Non-Cash Investing and Financing Activities			
The merger by issuance of stock	**$ 15,974**	—	—
Acquisition of Tosco by issuance of stock	**—**	7,049	—
Note payable to purchase properties, plants and equipment	**—**	25	111
Investment in properties, plants and equipment of businesses through the assumption of non-cash liabilities	**181**	125	472
Investment in equity affiliates through exchange of non-cash assets and liabilities*	**—**	(15)	4,272
Cash Payments			
Interest	**$ 441**	324	323
Income taxes	**1,363**	1,504	1,066

**On March 31, 2000, ConocoPhillips combined its gas gathering, processing and marketing business with the gas gathering, processing, marketing and natural gas liquids business of Duke Energy into DEFS and on July 1, 2000, ConocoPhillips and ChevronTexaco combined the two companies' worldwide chemicals businesses into CPChem.*

Note 24 — Other Financial Information

	Millions of Dollars Except Per Share Amounts		
	2002	2001	2000
Interest			
Incurred			
Debt	**$ 740**	524	511
Other	**58**	45	32
	798	569	543
Capitalized	**(232)**	(231)	(174)
Expensed	**$ 566**	338	369
Research and Development Expenditures — expensed	**$ 355***	44	43

**Includes $246 million of in-process research and development expenses related to the merger.*

Advertising Expenses*	**$ 37**	56	43

**Deferred amounts at December 31 were immaterial in all three years.*

Cash Dividends paid per common share	**$1.48**	1.40	1.36
Foreign Currency Transaction Gains (Losses) — after-tax			
E&P	**$ (34)**	2	(10)
R&M	**9**	3	(3)
Chemicals	**—**	—	(1)
Corporate and Other	**21**	(8)	(25)
	$ (4)	(3)	(39)

Note 25 — Related Party Transactions

Significant transactions with related parties were:

	Millions of Dollars		
	2002	2001	2000
Operating revenues (a)	**$ 1,554**	935	1,573
Purchases (b)	**1,545**	1,110	1,347
Operating expenses and selling, general and administrative expenses (c)	**279**	243	108
Net interest (income) expense (d)	**(6)**	8	(3)

(a) ConocoPhillips' Exploration and Production (E&P) segment sells natural gas to Duke Energy Field Services, LLC (DEFS) and crude oil to the Malaysian Refining Company Sdn. Bhd (Melaka), among others, for processing and marketing. Natural gas liquids, solvents and petrochemical feedstocks are sold to Chevron Phillips Chemical Company LLC (CPChem) and refined products are sold to CFJ Properties and GKG Mineraloelhandel GMbH & Co. KG. Also, the company charges several of its affiliates including CPChem; Merey Sweeny, L.P. (MSLP); Hamaca Holding LLC; and Venture Coke Company for the use of common facilities, such as steam generators, waste and water treaters, and warehouse facilities.

(b) ConocoPhillips purchases natural gas and natural gas liquids from DEFS and CPChem for use in its refinery processes and other feedstocks from various affiliates. ConocoPhillips purchases crude oil from Petrozuata C.A. and refined products from Melaka and Česká rafinérská, a.s. located in the Czech Republic. Also, ConocoPhillips pays fees to various pipeline equity companies for transporting finished refined products.

(c) ConocoPhillips pays processing fees to various affiliates, the most significant being MSLP. Additionally, ConocoPhillips pays contract drilling fees to two deepwater drillship affiliates. Fees are paid to ConocoPhillips' pipeline equity companies for transporting crude oil. Commissions are paid to the receivable monetization companies (see Note 13 — Sales of Receivables for more information).

(d) ConocoPhillips pays and/or receives interest to/from various affiliates including the receivable monetization companies and MSLP.

Elimination of the company's equity percentage share of profit or loss on the above transactions was not material.

Note 26 — Segment Disclosures and Related Information

ConocoPhillips has organized its reporting structure based on the grouping of similar products and services, resulting in five operating segments:

(1) E&P — This segment explores for and produces crude oil, natural gas, and natural gas liquids worldwide; and mines oil sands to extract bitumen and upgrade it into synthetic crude oil. At December 31, 2002, E&P was producing in the United States; the Norwegian and U.K. sectors of the North Sea; Canada; Nigeria; Venezuela; the Timor Sea; offshore Australia and China; Indonesia; the United Arab Emirates; Vietnam; Russia; and Ecuador. The E&P segment's U.S. and international operations are disclosed separately for reporting purposes.

(2) Midstream — Through both consolidated and equity interests, this segment gathers and processes natural gas produced by ConocoPhillips and others, and fractionates and markets natural gas liquids, primarily in the United States, Canada and Trinidad. The Midstream segment includes ConocoPhillips' 30.3 percent equity investment in DEFS.

(3) R&M — This segment refines, markets and transports crude oil and petroleum products, mostly in the United States, Europe and Asia. At December 31, 2002, ConocoPhillips owned 12 refineries in the United States (excluding two refineries treated as discontinued operations and reported in Corporate and Other); one in the United Kingdom; one in Ireland; and had equity interests in one refinery in Germany, two in the Czech Republic, and one in Malaysia. The R&M segment's U.S. and international operations are disclosed separately for reporting purposes.

(4) Chemicals — This segment manufactures and markets petrochemicals and plastics on a worldwide basis. The Chemicals segment consists primarily of ConocoPhillips' 50 percent equity investment in CPChem.

(5) Emerging Businesses — This segment encompasses the development of new businesses beyond the company's traditional operations. Emerging Businesses includes new technologies related to carbon fibers, natural gas conversion into clean fuels and related products (gas-to-liquids), fuels technology, and power generation.

Corporate and Other includes general corporate overhead; all interest income and expense; preferred dividend requirements of capital trusts; discontinued operations; restructuring charges; goodwill resulting from the merger of Conoco and Phillips that has not yet been allocated to the operating segments; certain eliminations; and various other corporate activities. Corporate assets include all cash and cash equivalents.

The company evaluates performance and allocates resources based on, among other items, net income. Segment accounting policies are the same as those in Note 1 — Accounting Policies. Intersegment sales are at prices that approximate market.

Analysis of Results by Operating Segment

	Millions of Dollars		
	2002	2001	2000
Sales and Other Operating Revenues			
E&P			
United States	**$ 7,222**	5,879	5,346
International	**4,850**	2,266	2,919
Intersegment eliminations — U.S.	**(1,304)**	(534)	(433)
Intersegment eliminations — international	**(484)**	—	(221)
E&P	**10,284**	7,611	7,611
Midstream			
Total sales	**2,049**	1,193	1,819
Intersegment eliminations	**(510)**	(416)	(665)
Midstream	**1,539**	777	1,154
R&M			
United States	**41,011**	16,445	11,570
International	**5,630**	142	532
Intersegment eliminations — U.S.	**(1,773)**	(92)	(361)
Intersegment eliminations — international	**—**	—	—
R&M	**44,868**	16,495	11,741
Chemicals			
Total sales	**13**	—	1,794
Intersegment eliminations	**—**	—	(147)
Chemicals	**13**	—	1,647
Emerging Businesses	**36**	7	—
Corporate and Other	**8**	2	2
Consolidated sales and other operating revenues	**$56,748**	24,892	22,155

	Millions of Dollars		
	2002	2001	2000
Depreciation, Depletion, Amortization and Impairments			
E&P			
United States	**$ 999**	817	552
International	**735**	324	487
Total E&P	**1,734**	1,141	1,039
Midstream	**19**	1	24
R&M			
United States	**564**	203	139
International	**50**	1	—
Total R&M	**614**	204	139
Chemicals	**—**	—	54
Emerging Businesses	**4**	—	—
Corporate and Other	**29**	24	13
Consolidated depreciation, depletion, amortization and impairments	**$ 2,400**	1,370	1,269

	Millions of Dollars		
	2002	2001	2000
Equity in Earnings of Affiliates			
E&P			
United States	**$ 29**	9	15
International	**162**	19	16
Total E&P	**191**	28	31
Midstream	**46**	165	137
R&M			
United States	**43**	88	28
International	**—**	—	8
Total R&M	**43**	88	36
Chemicals	**(16)**	(240)	(90)
Emerging Businesses	**(3)**	—	—
Corporate and Other	**—**	—	—
Consolidated equity in earnings of affiliates	**$ 261**	41	114

	Millions of Dollars		
	2002	2001	2000
Income Taxes			
E&P			
United States	**$ 473**	670	744
International	**1,337**	913	1,050
Total E&P	**1,810**	1,583	1,794
Midstream	**42**	73	91
R&M			
United States	**90**	210	115
International	**(11)**	—	10
Total R&M	**79**	210	125
Chemicals	**(18)**	(89)	21
Emerging Businesses	**(38)**	(7)	—
Corporate and Other	**(425)**	(126)	(131)
Consolidated income taxes	**$ 1,450**	1,644	1,900

	Millions of Dollars		
	2002	2001	2000
Net Income (Loss)			
E&P			
United States	**$ 1,156**	1,342	1,388
International	**593**	357	557
Total E&P	**1,749**	1,699	1,945
Midstream	**55**	120	162
R&M			
United States	**138**	395	209
International	**5**	2	29
Total R&M	**143**	397	238
Chemicals	**(14)**	(128)	(46)
Emerging Businesses	**(310)***	(12)	—
Corporate and Other	**(1,918)**	(415)	(437)
Consolidated net income (loss)	**$ (295)**	1,661	1,862

**Includes a non-cash $246 million write-off of acquired in-process research and development costs.*

	Millions of Dollars		
	2002	2001	2000
Investments In and Advances To Affiliates			
E&P			
United States	**$ 156**	13	5
International	**2,184**	573	342
Total E&P	**2,340**	586	347
Midstream	**318**	166	43
R&M			
United States	**762**	166	147
International	**416**	—	—
Total R&M	**1,178**	166	147
Chemicals	**2,050**	1,852	2,046
Emerging Businesses	**—**	—	—
Corporate and Other	**14**	18	29
Consolidated investments in and advances to affiliates	**$ 5,900**	2,788	2,612

	Millions of Dollars		
	2002	2001	2000
Total Assets			
E&P			
United States	**$14,196**	9,501	9,296
International	**19,541**	5,295	4,538
Total E&P	**33,737**	14,796	13,834
Midstream	**1,931**	196	145
R&M			
United States	**19,553**	14,553	3,112
International	**3,632**	183	68
Total R&M	**23,185**	14,736	3,180
Chemicals	**2,095**	1,934	2,170
Emerging Businesses	**737**	2	—
Corporate and Other	**15,151**	3,553	1,180
Consolidated total assets	**$76,836**	35,217	20,509

	Millions of Dollars		
	2002	2001	2000
Capital Expenditures and Investments*			
E&P			
United States	**$ 1,205**	1,354	951
International	**2,071**	1,162	726
Total E&P	**3,276**	2,516	1,677
Midstream	**5**	—	17
R&M			
United States	**676**	423	217
International	**164**	5	—
Total R&M	**840**	428	217
Chemicals	**60**	6	67
Emerging Businesses	**122**	—	—
Corporate and Other	**85**	66	39
Consolidated capital expenditures and investments	**$ 4,388**	3,016	2,017

**Including dry hole costs.*

Additional information on items included in Corporate and Other (on a before-tax basis unless otherwise noted):

	Millions of Dollars		
	2002	2001	2000
Interest income	**$ 40**	13	28
Interest expense	**566**	338	369
Extraordinary losses, after-tax	**16**	10	—
Significant non-cash items			
Impairments included in discontinued operations	**1,048**	—	—
Loss accruals related to retail site leases included in discontinued operations	**477**	—	—
Restructuring charges, net of benefits paid	**269**	—	—

Geographic Information

	Millions of Dollars					
	United States	Norway	United Kingdom	Canada	Other Foreign Countries	Worldwide Consolidated
2002						
Sales and Other Operating Revenues*	**$46,674**	**1,850**	**3,387**	**997**	**3,840**	**56,748**
Long-Lived Assets**	**$28,492**	**3,767**	**4,969**	**3,460**	**8,242**	**48,930**
2001						
Sales and Other Operating Revenues*	$22,466	1,322	380	42	682	24,892
Long-Lived Assets**	$19,955	1,484	654	29	2,799	24,921
2000						
Sales and Other Operating Revenues*	$18,700	231	2,183	175	866	22,155
Long-Lived Assets**	$13,198	1,487	709	30	1,831	17,255

**Sales and other operating revenues are attributable to countries based on the location of the operations generating the revenues.*
***Defined as net properties, plants and equipment plus investments in and advances to affiliates.*

Note 27 — New Accounting Standards

In June 2001, the FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations." SFAS No. 143 was adopted by the company on January 1, 2003, and requires major changes in the accounting for asset retirement obligations, such as required decommissioning of oil and gas production platforms, facilities and pipelines. SFAS No. 143 requires entities to record the fair value of a liability for an asset retirement obligation in the period when it is incurred (typically when the asset is installed at the production location). When the liability is initially recorded, the entity capitalizes the cost by increasing the carrying amount of the related property, plant and equipment. Over time, the liability is accreted for the change in its present value each period, and the initial capitalized cost is depreciated over the useful life of the related asset. Upon adoption of SFAS No. 143, the company adjusted its recorded asset retirement obligations to the new requirements using a cumulative-effect approach as required. All transition amounts were measured using the company's current information, assumptions, and credit-adjusted, risk-free interest rates. While the original discount rates used to establish an asset retirement obligation will not change in the future, changes in cost estimates or the timing of expenditures will result in immediate adjustments to the recorded liability, with an offsetting adjustment to properties, plants and equipment.

Application of the new rules, effective January 1, 2003, should result in an increase in net properties, plants and equipment of approximately $1.2 billion, an asset retirement obligation liability increase of approximately $1.1 billion, and a cumulative after-tax effect of adoption gain that is expected to increase net income and stockholders' equity by approximately $137 million. The estimated after-tax impact on income before extraordinary items and cumulative effect of changes in accounting principle for the year 2003 is an improvement of $33 million. The majority of the liability and asset increase is attributable to assets acquired in the merger, and production facilities in Alaska. Following prevalent oil and gas industry practice for acquisitions completed prior to January 1, 2003, ConocoPhillips did not record an initial liability for the estimated cost of removing properties, plants and equipment at the end of their useful lives. Instead, estimated removal costs were accrued on a unit-of-production basis as an additional component of depreciation, building the removal cost liability over the remaining useful lives of the properties, plants and equipment. However, upon adoption of SFAS No. 143, these asset retirement obligations are required to be recorded, significantly increasing asset retirement liabilities on the balance sheet with an offsetting increase to properties, plants and equipment.

In January 2003, the FASB issued Interpretation No. 46, "Consolidation of Variable Interest Entities," (VIEs) in an effort to expand upon and strengthen existing accounting guidance that addresses when a company should include in its financial statements the assets, liabilities and activities of another entity. In general, a VIE is a corporation, partnership, trust, or any other legal structure used for business purposes that either (a) does not have equity investors with voting rights or (b) has equity investors that do not provide sufficient financial resources for the entity to support its activities. Interpretation No. 46 requires a VIE to be consolidated by a company if that company is subject to a majority of the risk of loss from the VIE's activities, is entitled to receive a majority of the VIE's residual returns, or both. The interpretation also requires disclosures about VIEs that the company is not required to consolidate, but in which it has a significant variable interest. The consolidation requirements of Interpretation No. 46 applied immediately to variable interest entities created after January 31, 2003, and to older entities no later than the third quarter of 2003. The company is studying the impact of the interpretation on existing variable interest entities with which the company is involved. Certain of the disclosure requirements are required in all financial statements issued after January 31, 2003, regardless of when the variable interest entity was established. These are included in Note 28 — Variable Interest Entities.

In June 2002, the FASB issued SFAS No. 146, "Accounting for Costs Associated with Exit or Disposal Activities," which addresses financial accounting and reporting for costs associated with exit or disposal activities initiated after December 31, 2002, and nullifies Emerging Issues Task Force (EITF) Issue No. 94-3, "Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring)." SFAS No. 146 requires that a liability for a cost associated with an exit or disposal activity be recognized and measured initially at fair value at the date the liability is incurred, rather than at the commitment date. The company plans to apply the provisions of SFAS No. 146 prospectively for restructuring activities initiated in 2003 and future years. However, for restructuring activities initiated in 2002 the company will continue to apply EITF Issue Nos. 94-3 and 95-3 until those identified restructuring activities are completed. See Note 4 — Discontinued Operations and Note 5 — Restructuring for more information.

In November 2002, the FASB issued Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others." For specified guarantees issued or modified after December 31, 2002, the interpretation requires a guarantor to recognize, at the inception of the guarantee, a liability for the fair value of all the obligations it has undertaken in issuing the guarantee, including its ongoing obligation to stand ready and make cash payments over the term of the guarantee in the event that specified triggering events or conditions occur. The measurement of the liability for the fair value of the guarantee obligation should be based on the premium that would be required to issue the same guarantee in a stand-alone arm's-length transaction with an unrelated party if that information is available, or estimated using expected present value measurement techniques. For specified guarantees existing as of December 31, 2002, the interpretation also requires a guarantor to disclose (a) the nature of the guarantee, including how the guarantee arose and the events or circumstances that would require the guarantor to perform under the guarantee; (b) the maximum potential amount of future payments under the guarantee; (c) the carrying amount of the liability; and (d) the nature and extent of any recourse provisions or available collateral that would enable the guarantor to recover the amounts paid under the guarantee. The required disclosures are included in Note 14 — Guarantees.

In April 2002, the FASB issued SFAS No. 145, "Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections." The rescission of SFAS No. 4 will require that gains and losses on extinguishments of debt no longer be presented as extraordinary items in the income statement, commencing in 2003. All prior periods will be restated to reflect this change in presentation. See Note 2 — Extraordinary Items and Accounting Change.

In December 2002, the FASB issued SFAS No. 148, "Accounting for Stock-Based Compensation-Transition and Disclosure," an amendment of SFAS No. 123, "Accounting for Stock-Based Compensation," to provide alternative methods of transition for a voluntary change to the fair value method of accounting for stock-based employee compensation. ConocoPhillips adopted the fair-value method recommended by SFAS No. 123 on January 1, 2003, and is using the prospective transition method. See Note 20 — Employee Benefit Plans for more information on this accounting change.

In 2003, the FASB is expected to issue SFAS No. 149, "Accounting for Certain Financial Instruments with Characteristics of Liabilities and Equity," to address the balance sheet classification of certain financial instruments that have characteristics of both liabilities and equity. SFAS No. 149 is expected to provide that mandatorily redeemable instruments meet the conceptual definition of liabilities and must be presented as such on the balance sheet. The statement is expected to be effective upon issuance for all contracts created or modified after the issuance date and is otherwise effective on all previously existing contracts no later than the third quarter of 2003. ConocoPhillips is currently evaluating the impact of proposed SFAS No. 149, and it is likely that some or all of currently reported mandatorily redeemable preferred stock and minority interest securities will be reclassified as liabilities. See Note 17 — Preferred Stock and Other Minority Interests for more information.

Note 28 — Variable Interest Entities

In January 2003, the FASB issued Interpretation No. 46, "Consolidation of Variable Interest Entities," which provides guidance related to identifying variable interest entities and determining whether such entities should be consolidated. See Note 27 — New Accounting Standards for further explanation of this new accounting standard.

As required, the company will immediately apply this interpretation to variable interest entities created, or interests in variable interest entities obtained, after January 31, 2003. For variable interest entities created before February 1, 2003, the company will initially apply the guidance in this interpretation in the third quarter of 2003. At that time, if the company is determined to be the primary beneficiary of a variable interest entity created before February 1, 2003, the company will consolidate that entity. This interpretation excludes the QSPE's discussed in Note 13 — Sales of Receivables.

The company is still evaluating the impact of this very recent, complex interpretation on existing potential variable interest entities in which the company is involved. Based on a preliminary review, when the company initially applies the guidance of this interpretation in July 2003, it is reasonably possible that the company will be required to begin consolidating entities in the following areas:

- The company leases ocean transport vessels, drillships, corporate aircraft, service stations, office buildings, and certain refining equipment from special purpose entities (SPEs) that are third-party trusts established by a trustee and principally funded by financial institutions. If the company is required to consolidate all of these entities, the assets of the entities and debt of approximately $2.4 billion would be required to be included in the consolidated financial statements. The company's maximum exposure to loss as a result of its involvement with the entities would be the debt of the entity, less the fair value of the assets at the end of the lease terms. Of the $2.4 billion debt that would be consolidated, approximately $1.5 billion is associated with a major portion of the company's owned retail stores that the company has announced it plans to sell. As a result of the planned divestiture, the company plans to exercise purchase option provisions during 2003 and terminate various operating leases involving approximately 900 store sites and two office buildings. In addition, see Note 4 — Discontinued Operations for details regarding the provisions recorded for losses and penalties in the fourth quarter of 2002 for the planned divestiture. Depending upon the timing of the company's exercise of these purchase options, and the determination of whether or not the lessor entities in these operating leases are variable interest entities requiring consolidation in 2003, some or all of these lessor entities could become consolidated subsidiaries of the company prior to the exercise of the purchase options and termination of the leases. See Note 14 — Guarantees and Note 19 — Non-Mineral Leases.
- In December 2001, in order to raise funds for general corporate purposes, Conoco and Cold Spring Finance S.a.r.l. formed Ashford Energy Capital S.A. through the contribution of cash and a Conoco subsidiary promissory note. Through its $504 million investment, Cold Spring is entitled to a cumulative annual preferred return, based on three-month LIBOR rates plus 1.27 percent. The preferred return at December 31, 2002, was 2.70 percent. The company already consolidates Ashford and reports Cold Spring's investment as a minority interest. If it is determined that Cold Spring is a variable interest entity, the company may have to consolidate Cold Spring under Interpretation No. 46. If that were to occur, Cold Spring's financing of approximately $500 million at December 31, 2002, could be reported as debt of ConocoPhillips.

Oil and Gas Operations (Unaudited)

Exploration and Production

In accordance with SFAS No. 69, "Disclosures about Oil and Gas Producing Activities," and regulations of the U.S. Securities and Exchange Commission, the company is making certain supplemental disclosures about its oil and gas exploration and production operations. While this information was developed with reasonable care and disclosed in good faith, it is emphasized that some of the data is necessarily imprecise and represents only approximate amounts because of the subjective judgments involved in developing such information. Accordingly, this information may not necessarily represent the current financial condition of the company or its expected future results.

ConocoPhillips' disclosures by geographic areas include the United States (U.S.), Norway, the United Kingdom (U.K.), Canada and Other Areas. Other Areas include Nigeria, China, Australia, the Timor Sea, Indonesia, Vietnam, United Arab Emirates, Ecuador and other countries. When the company uses equity accounting for operations that have proved reserves, these oil and gas operations are shown separately and designated as Equity Affiliates. In 2002, these consisted of two heavy-oil projects in Venezuela, an oil development project in northern Russia and a heavy-oil project in Canada. In 2001 and 2000 this consisted of a heavy-oil project in Venezuela.

Amounts in 2000 were impacted by ConocoPhillips' purchase of all of Atlantic Richfield Company's (ARCO) Alaska businesses in late April 2000. Amounts in 2002 were impacted by the merger of Conoco and Phillips (the merger) in late August 2002.

Proved Reserves Worldwide

Years Ended December 31	Crude Oil									
	Millions of Barrels									
	Consolidated Operations									
	Alaska	Lower 48	Total U.S.	Norway	U.K.	Canada	Other Areas	Total	Equity Affiliates	Combined Total
Developed and Undeveloped										
End of 1999	33	109	142	521	57	12	232	964	—	964
Revisions	9	12	21	73	3	(2)	1	96	—	96
Improved recovery	31	—	31	5	—	—	—	36	—	36
Purchases	1,594	1	1,595	—	—	—	—	1,595	—	1,595
Extensions and discoveries	12	3	15	—	—	6	34	55	613	668
Production	(75)	(12)	(87)	(41)	(9)	(2)	(19)	(158)	—	(158)
Sales	—	(1)	(1)	—	—	(12)	—	(13)	—	(13)
End of 2000	1,604	112	1,716	558	51	2	248	2,575	613	3,188
Revisions	77	(2)	75	51	(6)	—	4	124	48	172
Improved recovery	67	1	68	12	—	—	—	80	—	80
Purchases	—	—	—	—	—	—	17	17	—	17
Extensions and discoveries	9	6	15	—	2	—	12	29	—	29
Production	(126)	(12)	(138)	(43)	(6)	—	(19)	(206)	(1)	(207)
Sales	—	—	—	—	—	—	(3)	(3)	—	(3)
End of 2001	1,631	105	1,736	578	41	2	259*	2,616	660	3,276
Revisions	**32**	**(8)**	**24**	**(26)**	**(5)**	**5**	**(32)**	**(34)**	**(27)**	**(61)**
Improved recovery	**46**	**1**	**47**	**5**	**2**	**—**	**—**	**54**	**—**	**54**
Purchases	**—**	**132**	**132**	**262**	**143**	**101**	**223**	**861**	**733**	**1,594**
Extensions and discoveries	**14**	**6**	**20**	**3**	**3**	**1**	**22**	**49**	**4**	**53**
Production	**(120)**	**(14)**	**(134)**	**(58)**	**(14)**	**(5)**	**(24)**	**(235)**	**(13)**	**(248)**
Sales	**—**	**(2)**	**(2)**	**(13)**	**(7)**	**(13)**	**(1)**	**(36)**	**—**	**(36)**
End of 2002	**1,603**	**220**	**1,823**	**751**	**163**	**91**	**447****	**3,275**	**1,357**	**4,632**
Developed										
End of 1999	25	93	118	433	37	10	114	712	—	712
End of 2000	1,207	98	1,305	478	25	2	116	1,926	—	1,926
End of 2001	1,275	91	1,366	513	21	2	96	1,998	47	2,045
End of 2002	**1,335**	**169**	**1,504**	**611**	**102**	**81**	**223**	**2,521**	**378**	**2,899**

**Includes proved reserves of 17 million barrels attributable to a consolidated subsidiary in which there is a 13 percent minority interest.*
***Includes proved reserves of 14 million barrels attributable to a consolidated subsidiary in which there is a 10 percent minority interest.*

- Purchases in 2002 were primarily related to the merger. Other Areas in 2002 includes 1 million barrels related to an operation that was classified as discontinued following the merger, and was sold by year-end. The amount for this operation was not included in the schedule of sources of change in discounted future net cash flows, or as a part of the company's per-unit finding and development cost calculation.
- At the end of 2000 and 1999, Other Areas included 2 million and 14 million barrels, respectively, of reserves in Venezuela in which the company had an economic interest through risk-service contracts. These properties were sold in June 2001. Net production to the company was approximately 400,000 barrels in 2001; 1,200,000 barrels in 2000; and 600,000 barrels in 1999.
- In addition to conventional crude oil, natural gas and natural gas liquids (NGL) proved reserves, ConocoPhillips has proven oil sands reserves in Canada, associated with a Syncrude project totaling 272 million barrels at the end of 2002. For internal management purposes, ConocoPhillips views these reserves and their development as part of its total exploration and production operations. However, U.S. Securities and Exchange Commission regulations define these reserves as mining related. Therefore, they are not included in the company's tabular presentation of proved crude oil, natural gas and NGL reserves. These oil sand reserves are also not included in the standardized measure of discounted future net cash flows relating to proved oil and gas reserve quantities.

Years Ended December 31	Natural Gas — Billions of Cubic Feet — Consolidated Operations									
	Alaska	Lower 48	Total U.S.	Norway	U.K.	Canada	Other Areas	Total	Equity Affiliates	Combined Total
Developed and Undeveloped										
End of 1999	798	2,554	3,352	1,176	681	521	634	6,364	—	6,364
Revisions	87	183	270	(162)	10	(200)	1	(81)	—	(81)
Improved recovery	—	—	—	52	—	—	—	52	—	52
Purchases	2,448	193	2,641	—	—	—	—	2,641	—	2,641
Extensions and discoveries	7	211	218	—	—	22	4	244	131	375
Production	(103)	(283)	(386)	(54)	(79)	(33)	(14)	(566)	—	(566)
Sales	—	(5)	(5)	—	—	(246)	—	(251)	—	(251)
End of 2000	3,237	2,853	6,090	1,012	612	64	625	8,403	131	8,534
Revisions	60	9	69	(65)	(59)	(2)	64	7	14	21
Improved recovery	—	—	—	13	—	—	—	13	—	13
Purchases	—	12	12	—	10	—	10	32	—	32
Extensions and discoveries	5	405	410	—	23	—	374	807	—	807
Production	(141)	(261)	(402)	(53)	(68)	(7)	(40)	(570)	—	(570)
Sales	—	—	—	—	(8)	—	—	(8)	—	(8)
End of 2001	3,161	3,018	6,179	907	510	55	1,033*	8,684	145	8,829
Revisions	**(27)**	**(70)**	**(97)**	**4**	**(24)**	**16**	**(75)**	**(176)**	**—**	**(176)**
Improved recovery	**5**	**1**	**6**	**13**	**1**	**—**	**—**	**20**	**—**	**20**
Purchases	**—**	**1,862**	**1,862**	**1,003**	**1,580**	**1,241**	**2,062**	**7,748**	**17**	**7,765**
Extensions and discoveries	**2**	**225**	**227**	**—**	**43**	**21**	**420**	**711**	**1**	**712**
Production	**(147)**	**(340)**	**(487)**	**(68)**	**(158)**	**(59)**	**(68)**	**(840)**	**(2)**	**(842)**
Sales	**(5)**	**(1)**	**(6)**	**(1)**	**(3)**	**(97)**	**(161)**	**(268)**	**—**	**(268)**
End of 2002	**2,989**	**4,695**	**7,684**	**1,858**	**1,949**	**1,177**	**3,211****	**15,879**	**161**	**16,040**
Developed										
End of 1999	630	2,317	2,947	856	413	131	349	4,696	—	4,696
End of 2000	2,969	2,564	5,533	738	321	54	336	6,982	—	6,982
End of 2001	2,969	2,684	5,653	788	265	45	736	7,487	3	7,490
End of 2002	**2,806**	**4,302**	**7,108**	**1,544**	**1,734**	**1,098**	**1,349**	**12,833**	**28**	**12,861**

**Includes proved reserves of 10 billion cubic feet attributable to a consolidated subsidiary in which there is a 13 percent minority interest.*

***Includes proved reserves of 10 billion cubic feet attributable to a consolidated subsidiary in which there is a 10 percent minority interest.*

- Natural gas production may differ from gas production (delivered for sale) in the company's statistics disclosure, primarily because the quantities above include gas consumed at the lease, but omit the gas equivalent of liquids extracted at any ConocoPhillips-owned, equity-affiliate, or third-party processing plant or facility.
- Purchases in 2002 were related to the merger. Other Areas in 2002 includes 161 billion cubic feet related to an operation that was classified as discontinued following the merger, and was sold by year-end. The amount for this operation was not included in the schedule of sources of change in discounted future net cash flows, or as a part of the company's per-unit finding and development cost calculation.
- Extensions and discoveries in Other Areas in 2002 were primarily in Nigeria.
- Sales in Other Areas in 2002 were for a discontinued operation. See note on purchases above.
- Natural gas reserves are computed at 14.65 pounds per square inch absolute and 60 degrees Fahrenheit.

Years Ended December 31	Natural Gas Liquids									
	Millions of Barrels									
	Consolidated Operations									
	Alaska	Lower 48	Total U.S.	Norway	U.K.	Canada	Other Areas	Total	Equity Affiliates	Combined Total
Developed and Undeveloped										
End of 1999	1	91	92	29	4	4	78	207	—	207
Revisions	57	11	68	7	—	(2)	2	75	—	75
Purchases	147	—	147	—	—	—	—	147	—	147
Extensions and discoveries	—	2	2	—	—	—	—	2	—	2
Production	(7)	(8)	(15)	(2)	(1)	—	(1)	(19)	—	(19)
Sales	—	—	—	—	—	(2)	(1)	(3)	—	(3)
End of 2000	198	96	294	34	3	—	78	409	—	409
Revisions	(25)	2	(23)	—	—	—	4	(19)	—	(19)
Improved recovery	—	—	—	1	—	—	—	1	—	1
Purchases	—	—	—	—	—	—	10	10	—	10
Extensions and discoveries	—	2	2	—	—	—	—	2	—	2
Production	(9)	(7)	(16)	(2)	—	—	(1)	(19)	—	(19)
End of 2001	164	93	257	33	3	—	91*	384	—	384
Revisions	**(4)**	**5**	**1**	**(3)**	**2**	**—**	**(11)**	**(11)**	**—**	**(11)**
Improved recovery	**—**	**1**	**1**	**—**	**—**	**—**	**—**	**1**	**—**	**1**
Purchases	**—**	**80**	**80**	**12**	**2**	**38**	**21**	**153**	**—**	**153**
Extensions and discoveries	**—**	**4**	**4**	**—**	**—**	**1**	**—**	**5**	**—**	**5**
Production	**(9)**	**(9)**	**(18)**	**(2)**	**(1)**	**(2)**	**(1)**	**(24)**	**—**	**(24)**
Sales	**—**	**—**	**—**	**—**	**—**	**(2)**	**(1)**	**(3)**	**—**	**(3)**
End of 2002	**151**	**174**	**325**	**40**	**6**	**35**	**99****	**505**	**—**	**505**
Developed										
End of 1999	1	89	90	22	3	1	17	133	—	133
End of 2000	197	94	291	27	2	1	17	338	—	338
End of 2001	163	92	255	29	2	—	16	302	—	302
End of 2002	**151**	**166**	**317**	**34**	**6**	**30**	**15**	**402**	**—**	**402**

**Includes proved reserves of 10 million barrels attributable to a consolidated subsidiary in which there is a 13 percent minority interest.*
***Includes proved reserves of 9 million barrels attributable to a consolidated subsidiary in which there is a 10 percent minority interest.*

■ Natural gas liquids reserves include estimates of natural gas liquids to be extracted from ConocoPhillips' leasehold gas at gas processing plants or facilities. Estimates are based at the wellhead and assume full extraction. Production above differs from natural gas liquids production per day delivered for sale primarily due to:
(1) Natural gas consumed at the lease.
(2) Natural gas liquids production delivered for sale includes only natural gas liquids extracted from ConocoPhillips' leasehold gas and sold by ConocoPhillips' Exploration and Production (E&P) segment, whereas the production above also includes natural gas liquids extracted from ConocoPhillips' leasehold gas at equity-affiliate or third-party facilities.

■ Purchases in 2002 were related to the merger.

Results of Operations

Years Ended December 31	Millions of Dollars									
	Consolidated Operations									
	Alaska	Lower 48	Total U.S.	Norway	U.K.	Canada	Other Areas	Total	Equity Affiliates	Combined Total
2002										
Sales	**$2,997**	**927**	**3,924**	**400**	**794**	**125**	**747**	**5,990**	**180**	**6,170**
Transfers	**102**	**401**	**503**	**1,285**	**30**	**235**	**—**	**2,053**	**62**	**2,115**
Other revenues	**(2)**	**3**	**1**	**35**	**28**	**7**	**21**	**92**	**12**	**104**
Total revenues	**3,097**	**1,331**	**4,428**	**1,720**	**852**	**367**	**768**	**8,135**	**254**	**8,389**
Production costs	**769**	**444**	**1,213**	**209**	**134**	**118**	**190**	**1,864**	**57**	**1,921**
Exploration expenses	**101**	**108**	**209**	**33**	**34**	**32**	**276***	**584**	**—**	**584**
Depreciation, depletion and amortization	**552**	**334**	**886**	**206**	**274**	**105**	**85**	**1,556**	**30**	**1,586**
Property impairments	**4**	**8**	**12**	**—**	**41**	**—**	**—**	**53**	**—**	**53**
Transportation costs	**681**	**87**	**768**	**75**	**50**	**—**	**15**	**908**	**8**	**916**
Other related expenses	**23**	**16**	**39**	**60**	**15**	**14**	**12**	**140**	**12**	**152**
	967	**334**	**1,301**	**1,137**	**304**	**98**	**190**	**3,030**	**147**	**3,177**
Provision for income taxes	**294**	**66**	**360**	**857**	**124**	**49**	**275**	**1,665**	**(18)**	**1,647**
Results of operations for producing activities	**673**	**268**	**941**	**280**	**180**	**49**	**(85)**	**1,365**	**165**	**1,530**
Other earnings	**197**	**18**	**215**	**20**	**(10)**	**24****	**(6)**	**243**	**(24)**	**219**
E&P net income (loss)	**$ 870**	**286**	**1,156**	**300**	**170**	**73**	**(91)**	**1,608**	**141**	**1,749**
2001										
Sales	$3,020	1,178	4,198	175	371	31	478	5,253	8	5,261
Transfers	119	119	238	1,039	—	—	—	1,277	—	1,277
Other revenues	34	26	60	13	10	5	(4)	84	1	85
Total revenues	3,173	1,323	4,496	1,227	381	36	474	6,614	9	6,623
Production costs	784	328	1,112	124	41	6	92	1,375	2	1,377
Exploration expenses	61	69	130	20	11	—	154	315	—	315
Depreciation, depletion and amortization	531	203	734	115	118	4	49	1,020	2	1,022
Property impairments	—	—	—	—	—	—	23	23	—	23
Transportation costs	726	77	803	27	33	3	6	872	—	872
Other related expenses	2	5	7	—	(8)	1	28	28	2	30
	1,069	641	1,710	941	186	22	122	2,981	3	2,984
Provision for income taxes	392	173	565	729	50	7	139	1,490	—	1,490
Results of operations for producing activities	677	468	1,145	212	136	15	(17)	1,491	3	1,494
Other earnings	189	8	197	17	—	—	(9)	205	—	205
E&P net income (loss)	$ 866	476	1,342	229	136	15	(26)	1,696	3	1,699
2000										
Sales	$2,252	1,102	3,354	139	481	169	556	4,699	—	4,699
Transfers	74	275	349	1,186	—	—	—	1,535	—	1,535
Other revenues	9	25	34	5	(1)	140	(2)	176	—	176
Total revenues	2,335	1,402	3,737	1,330	480	309	554	6,410	—	6,410
Production costs	494	308	802	118	42	35	100	1,097	—	1,097
Exploration expenses	38	73	111	14	36	5	138	304	—	304
Depreciation, depletion and amortization	305	190	495	106	138	68	65	872	—	872
Property impairments	—	13	13	—	—	—	87	100	—	100
Transportation costs	364	101	465	27	39	9	5	545	—	545
Other related expenses	(9)	4	(5)	21	(2)	4	32	50	—	50
	1,143	713	1,856	1,044	227	188	127	3,442	—	3,442
Provision for income taxes	443	207	650	817	69	13	153	1,702	—	1,702
Results of operations for producing activities	700	506	1,206	227	158	175	(26)	1,740	—	1,740
Other earnings	129	53	182	16	(1)	—	8	205	—	205
E&P net income (loss)	$ 829	559	1,388	243	157	175	(18)	1,945	—	1,945

Includes a $77 million leasehold impairment charge for an investment in Angola.
***Includes $27 million for a Syncrude oil project in Canada that is defined as a mining operation by U.S. Securities and Exchange Commission regulations.*

- Results of operations for producing activities consist of all the activities within the E&P organization, except for pipeline and marine operations, a liquefied natural gas operation, Syncrude operations, and crude oil and gas marketing activities, which are included in Other earnings. Also excluded are non-E&P activities, including ConocoPhillips' Midstream segment, downstream petroleum and chemical activities, as well as general corporate administrative expenses and interest.
- Transfers are valued at prices that approximate market.
- Other revenues include gains and losses from asset sales, certain amounts resulting from the purchase and sale of hydrocarbons, and other miscellaneous income.
- Production costs consist of costs incurred to operate and maintain wells and related equipment and facilities used in the production of petroleum liquids and natural gas. These costs also include taxes other than income taxes, depreciation of support equipment and administrative expenses related to the production activity. Excluded are depreciation, depletion and amortization of capitalized acquisition, exploration and development costs.
- Exploration expenses include dry hole, leasehold impairment, geological and geophysical expenses and the cost of retaining undeveloped leaseholds. Also included are taxes other than income taxes, depreciation of support equipment and administrative expenses related to the exploration activity.
- Exploration expenses in 2002 included $77 million for the impairment of a substantial portion of the company's investment in deepwater Block 34, offshore Angola. Initial results released in early May 2002 indicated that the first exploratory well drilled in Block 34 was a dry hole, resulting in ConocoPhillips' reassessment of the fair value of the remainder of the block.
- Depreciation, depletion and amortization (DD&A) in Results of Operations differs from that shown for total E&P in Note 26 — Segment Disclosures and Related Information in the Notes to Consolidated Financial Statements, mainly due to depreciation of support equipment being reclassified to production or exploration expenses, as applicable, in Results of Operations. In addition, Other earnings include certain E&P activities, including their related DD&A charges.
- Transportation costs include costs to transport oil, natural gas or natural gas liquids to their points of sale. The profit element of transportation operations in which the company has an ownership interest are deemed to be outside the oil and gas producing activity. The net income of the transportation operations is included in Other earnings.
- Other related expenses include foreign currency gains and losses, and other miscellaneous expenses.
- The provision for income taxes is computed by adjusting each country's income before income taxes for permanent differences related to the oil and gas producing activities that are reflected in the company's consolidated income tax expense for the period, multiplying the result by the country's statutory tax rate and adjusting for applicable tax credits.
- Other earnings consist of activities within the E&P segment that are not a part of the "Results of operations for producing activities." These non-producing activities include pipeline and marine operations, liquefied natural gas operations, Syncrude operations, and crude oil and gas marketing activities.

Statistics

Net Production	**2002**	2001	2000
	Thousands of Barrels Daily		
Crude Oil			
Alaska	**331**	339	207
Lower 48	**40**	34	34
United States	**371**	373	241
Norway	**157**	117	114
United Kingdom	**39**	19	25
Canada	**13**	1	6
Other areas	**67**	51	51
Total consolidated	**647**	561	437
Equity affiliates	**35**	2	—
	682	563	437
Natural Gas Liquids*			
Alaska	**24**	25	19
Lower 48	**8**	1	1
United States	**32**	26	20
Norway	**6**	5	5
United Kingdom	**2**	2	2
Canada	**4**	—	1
Other areas	**2**	2	1
	46	35	29

Represents amounts extracted attributable to E&P operations (see natural gas liquids reserves for further discussion). Includes for 2002, 2001 and 2000, 14,000, 15,000 and 12,000 barrels daily in Alaska, respectively, that were sold from the Prudhoe Bay lease to the Kuparuk lease for reinjection to enhance crude oil production.

Natural Gas*	Millions of Cubic Feet Daily		
Alaska	**175**	177	158
Lower 48	**928**	740	770
United States	**1,103**	917	928
Norway	**171**	130	136
United Kingdom	**424**	178	214
Canada	**165**	18	83
Other areas	**180**	92	33
Total consolidated	**2,043**	1,335	1,394
Equity affiliates	**4**	—	—
	2,047	1,335	1,394

Represents quantities available for sale. Excludes gas equivalent of natural gas liquids shown above.

Average Sales Prices			
Crude Oil			
Per Barrel			
Alaska	**$23.75**	23.60	28.87
Lower 48	**24.48**	23.27	28.57
United States	**23.83**	23.57	28.83
Norway	**25.21**	24.02	28.27
United Kingdom	**25.33**	24.52	28.19
Canada	**22.87**	26.96	28.21
Other areas	**25.33**	24.30	28.87
Total international	**25.14**	24.16	28.42
Total consolidated	**24.38**	23.77	28.65
Equity affiliates	**18.41**	12.36	—
Worldwide	**24.07**	23.74	28.65

	2002	2001	2000
Average Sales Prices *(continued)*			
Natural Gas Liquids			
Per Barrel			
Alaska	**$ 23.48**	23.61	28.97
Lower 48	**15.66**	22.47	22.97
United States	**20.00**	23.49	27.94
Norway	**16.51**	16.55	14.13
United Kingdom	**20.61**	18.49	20.57
Canada	**20.39**	18.77	25.49
Other areas	**7.23**	7.22	7.18
Total international	**17.47**	14.61	15.14
Worldwide	**18.93**	19.74	21.20
Natural Gas (Lease)			
Per Thousand Cubic Feet			
Alaska	**$ 1.85**	1.75	1.40
Lower 48	**2.79**	3.68	3.56
United States	**2.75**	3.56	3.47
Norway	**3.20**	3.53	2.56
United Kingdom	**2.92**	2.88	2.61
Canada	**3.03**	3.80	3.26
Other areas	**1.90**	.50	.50
Total international	**2.79**	2.60	2.56
Total consolidated	**2.77**	3.23	3.13
Equity affiliates	**2.71**	—	—
Worldwide	**2.77**	3.23	3.13
Average Production Costs			
Per Barrel of Oil Equivalent			
Alaska	**$ 5.48**	5.46	5.35
Lower 48	**6.00**	5.67	5.15
United States	**5.66**	5.52	5.27
Norway	**2.99**	2.36	2.28
United Kingdom	**3.29**	2.22	1.83
Canada	**7.26**	4.08	4.59
Other areas	**5.26**	3.69	4.75
Total international	**3.99**	2.70	2.85
Total consolidated	**4.94**	4.60	4.29
Equity affiliates	**4.38**	2.74	—
Worldwide	**4.92**	4.60	4.29
Depreciation, Depletion and Amortization Per Barrel of Oil Equivalent			
Alaska	**$ 3.94**	3.70	3.30
Lower 48	**4.52**	3.51*	3.18
United States	**4.14**	3.58	3.25
Norway	**2.95**	2.19	2.04
United Kingdom	**6.73**	6.38	6.02
Canada	**6.46**	2.72	8.91
Other areas	**2.35**	1.96	3.09
Total international	**4.11**	2.94	3.64
Total consolidated	**4.13**	3.37	3.41
Equity affiliates	**2.30**	2.74	—
Worldwide	**4.06**	3.37	3.41

Includes a $12 million charge related to an asset transfer.

Net Wells Completed*	Productive			Dry		
	2002	2001	2000	**2002**	2001	2000
Exploratory						
Alaska	**—**	1	—	**4**	1	1
Lower 48	**29**	63	45	**6**	3	4
United States	**29**	64	45	**10**	4	5
Norway	**—**	**	**	**	—	—
United Kingdom	**	**	1	**2**	1	1
Canada	**19**	—	3	**2**	—	1
Other areas	**2**	2	6	**7**	1	6
Total consolidated	**50**	66	55	**21**	6	13
Equity affiliates	**3**	—	—	**1**	—	—
	53	66	55	**22**	6	13
Development						
Alaska	**48**	47	52	**1**	2	1
Lower 48	**283**	333	208	**14**	11	8
United States	**331**	380	260	**15**	13	9
Norway	**4**	3	1	**—**	—	—
United Kingdom	**7**	1	1	**—**	—	—
Canada	**20**	5	8	**1**	—	1
Other areas	**13**	2	6	**	—	—
Total consolidated	**375**	391	276	**16**	13	10
Equity affiliates	**49**	20	—	**1**	—	—
	424	411	276	**17**	13	10

Includes wildcat and production step-out wells. Excludes farmout arrangements.
***ConocoPhillips' total proportionate interest was less than one.*

Wells at Year-End 2002			Productive**			
	In Progress*		Oil		Gas	
	Gross	Net	Gross	Net	Gross	Net
Alaska	**25**	**15**	**1,680**	**735**	**24**	**15**
Lower 48	**101**	**61**	**11,801**	**2,826**	**15,534**	**7,586**
United States	**126**	**76**	**13,481**	**3,561**	**15,558**	**7,601**
Norway	**13**	**2**	**519**	**85**	**60**	**7**
United Kingdom	**14**	**5**	**189**	**37**	**288**	**87**
Canada	**7**	**5**	**3,395**	**2,408**	**5,359**	**3,463**
Other areas	**33**	**16**	**943**	**321**	**76**	**31**
Total consolidated	**193**	**104**	**18,527**	**6,412**	**21,341**	**11,189**
Equity affiliates	**4**	**2**	**2,095**	**875**	**161**	**63**
	197	**106**	**20,622**	**7,287**	**21,502**	**11,252**

Includes wells that have been temporarily suspended.
***Includes 3,205 gross and 1,554 net multiple completion wells.*

Acreage at December 31, 2002	Thousands of Acres	
	Gross	Net
Developed		
Alaska	**878**	**431**
Lower 48	**5,219**	**3,142**
United States	**6,097**	**3,573**
Norway	**430**	**47**
United Kingdom	**1,496**	**465**
Canada	**4,764**	**2,343**
Other areas	**5,147**	**2,128**
Total consolidated	**17,934**	**8,556**
Equity affiliates	**490**	**151**
	18,424	**8,707**
Undeveloped		
Alaska	**2,467**	**1,422**
Lower 48	**3,494**	**2,115**
United States	**5,961**	**3,537**
Norway	**5,243**	**1,309**
United Kingdom	**3,298**	**1,379**
Canada	**13,631**	**7,716**
Other areas*	**118,115**	**78,324**
Total consolidated	**146,248**	**92,265**
Equity affiliates	**2,118**	**943**
	148,366	**93,208**

Includes two Somalia concessions where operations have been suspended by declarations of force majeure totaling 33,905 thousand gross and net acres.

Costs Incurred

	Millions of Dollars									
	Consolidated Operations									
	Alaska	Lower 48	Total U.S.	Norway	U.K.	Canada	Other Areas	Total	Equity Affiliates	Combined Total
2002										
Acquisition	**$ 9**	**3,735**	**3,744**	**1,348**	**3,050**	**2,562**	**2,064**	**12,768**	**1,671**	**14,439**
Exploration	**94**	**112**	**206**	**33**	**28**	**58**	**309**	**634**	**1**	**635**
Development	**433**	**409**	**842**	**174**	**232**	**46**	**857**	**2,151**	**467**	**2,618**
	$ 536	**4,256**	**4,792**	**1,555**	**3,310**	**2,666**	**3,230**	**15,553**	**2,139**	**17,692**
2001										
Acquisition	$ 17	37	54	—	—	—	228	282	—	282
Exploration	93	57	150	26	18	—	223	417	—	417
Development	610	312	922	94	75	3	401	1,495	420	1,915
	$ 720	406	1,126	120	93	3	852	2,194	420	2,614
2000										
Acquisition	$5,787	151	5,938	36	—	33	5	6,012	3	6,015
Exploration	32	66	98	17	36	6	213	370	—	370
Development	422	218	640	71	50	42	192	995	135	1,130
	$6,241	435	6,676	124	86	81	410	7,377	138	7,515

- Costs incurred include capitalized and expensed items.
- Acquisition costs include the costs of acquiring proved and unproved oil and gas properties. The amounts in 2002 relate primarily to the merger. Acquisition costs included proved properties of $3,420 million, $13 million and $87 million in the Lower 48 for 2002, 2001, and 2000, respectively. The 2002 amounts in Norway and the U.K. included $1,255 million and $2,464 million for proved properties, respectively. The 2002 and 2000 amounts in Canada included proved properties of $2,003 million and $33 million, respectively. The 2002 and 2001 amounts in Other Areas included $1,493 million and $63 million for proved properties. The 2002 amount for Equity Affiliates of $1,671 million is for proved properties. The 2000 amount in Alaska included $5,125 million for proved properties.
- Exploration costs include geological and geophysical expenses, the cost of retaining undeveloped leaseholds, and exploratory drilling costs.
- Development costs include the cost of drilling and equipping development wells and building related production facilities for extracting, treating, gathering and storing petroleum liquids and natural gas.

Capitalized Costs

At December 31	Millions of Dollars									
	Consolidated Operations									
	Alaska	Lower 48	Total U.S.	Norway	U.K.	Canada	Other Areas	Total	Equity Affiliates	Combined Total
2002										
Proved properties	**$7,037**	**7,737**	**14,774**	**5,422**	**4,178**	**2,023**	**3,832**	**30,229**	**2,847**	**33,076**
Unproved properties	**849**	**489**	**1,338**	**142**	**622**	**546**	**1,556**	**4,204**	**—**	**4,204**
	7,886	**8,226**	**16,112**	**5,564**	**4,800**	**2,569**	**5,388**	**34,433**	**2,847**	**37,280**
Accumulated depreciation, depletion and amortization	**1,636**	**2,891**	**4,527**	**2,224**	**1,033**	**182**	**661**	**8,627**	**37**	**8,664**
	$6,250	**5,335**	**11,585**	**3,340**	**3,767**	**2,387**	**4,727**	**25,806**	**2,810**	**28,616**
2001										
Proved properties	$6,646	4,552	11,198	2,889	1,773	104	1,752	17,716	708	18,424
Unproved properties	772	181	953	40	41	3	768	1,805	—	1,805
	7,418	4,733	12,151	2,929	1,814	107	2,520	19,521	708	20,229
Accumulated depreciation, depletion and amortization	1,097	3,238	4,335	1,529	1,161	79	540	7,644	4	7,648
	$6,321	1,495	7,816	1,400	653	28	1,980	11,877	704	12,581

- Capitalized costs include the cost of equipment and facilities for oil and gas producing activities. These costs include the activities of ConocoPhillips' E&P organization, excluding pipeline and marine operations, the Kenai liquefied natural gas operation, Syncrude operations, and crude oil and natural gas marketing activities.
- Proved properties include capitalized costs for oil and gas leaseholds holding proved reserves; development wells and related equipment and facilities (including uncompleted development well costs); and support equipment.
- Unproved properties include capitalized costs for oil and gas leaseholds under exploration (including where petroleum liquids and natural gas were found but determination of the economic viability of the required infrastructure is dependent upon further exploratory work under way or firmly planned) and for uncompleted exploratory well costs, including exploratory wells under evaluation.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserve Quantities

Amounts are computed using year-end prices and costs (adjusted only for existing contractual changes), appropriate statutory tax rates and a prescribed 10 percent discount factor. Continuation of year-end economic conditions also is assumed. The calculation is based on estimates of proved reserves, which are revised over time as new data become available. Probable or possible reserves, which may become proved in the future, are not considered. The calculation also requires assumptions as to the timing of future production of proved reserves, and the timing and amount of future development and production costs.

While due care was taken in its preparation, the company does not represent that this data is the fair value of the company's oil and gas properties, or a fair estimate of the present value of cash flows to be obtained from their development and production.

Discounted Future Net Cash Flows

	Millions of Dollars									
	Consolidated Operations									
	Alaska	Lower 48	Total U.S.	Norway	U.K.	Canada	Other Areas	Total	Equity Affiliates	Combined Total
2002										
Future cash inflows	**$54,497**	**28,679**	**83,176**	**29,571**	**11,709**	**8,076**	**22,654**	**155,186**	**32,983**	**188,169**
Less:										
Future production and transportation costs	**26,035**	**7,763**	**33,798**	**4,598**	**3,376**	**1,885**	**5,403**	**49,060**	**4,992**	**54,052**
Future development costs	**2,927**	**1,168**	**4,095**	**1,762**	**1,227**	**617**	**2,249**	**9,950**	**1,698**	**11,648**
Future income tax provisions	**7,665**	**5,349**	**13,014**	**16,998**	**3,077**	**2,361**	**6,912**	**42,362**	**8,501**	**50,863**
Future net cash flows	**17,870**	**14,399**	**32,269**	**6,213**	**4,029**	**3,213**	**8,090**	**53,814**	**17,792**	**71,606**
10 percent annual discount	**9,097**	**7,405**	**16,502**	**2,515**	**1,483**	**1,422**	**3,730**	**25,652**	**11,585**	**37,237**
Discounted future net cash flows	**$ 8,773**	**6,994**	**15,767**	**3,698**	**2,546**	**1,791**	**4,360***	**28,162**	**6,207**	**34,369**
2001										
Future cash inflows	$33,138	9,441	42,579	14,278	2,143	174	6,712	65,886	11,581	77,467
Less:										
Future production and transportation costs	20,541	4,241	24,782	2,117	357	52	1,426	28,734	3,483	32,217
Future development costs	3,071	530	3,601	627	248	9	1,079	5,564	1,282	6,846
Future income tax provisions	1,797	1,253	3,050	8,762	389	8	2,596	14,805	2,133	16,938
Future net cash flows	7,729	3,417	11,146	2,772	1,149	105	1,611	16,783	4,683	21,466
10 percent annual discount	3,297	1,821	5,118	1,247	360	44	1,019	7,788	3,687	11,475
Discounted future net cash flows	$ 4,432	1,596	6,028	1,525	789	61	592**	8,995	996	9,991
2000										
Future cash inflows	$39,554	29,027	68,581	16,002	3,012	537	7,792	95,924	14,812	110,736
Less:										
Future production and transportation costs	20,338	3,996	24,334	2,060	426	105	1,379	28,304	2,519	30,823
Future development costs	2,916	479	3,395	679	372	1	1,024	5,471	1,684	7,155
Future income tax provisions	3,772	8,206	11,978	10,103	592	160	2,316	25,149	2,546	27,695
Future net cash flows	12,528	16,346	28,874	3,160	1,622	271	3,073	37,000	8,063	45,063
10 percent annual discount	5,660	8,684	14,344	1,429	571	113	1,761	18,218	6,428	24,646
Discounted future net cash flows	$ 6,868	7,662	14,530	1,731	1,051	158	1,312	18,782	1,635	20,417

**Includes $139 million attributable to a consolidated subsidiary in which there is a 10 percent minority interest.*
***Includes $17 million attributable to a consolidated subsidiary in which there is a 13 percent minority interest.*
Excludes discounted future net cash flows from Canadian Syncrude of $869 million.

Sources of Change in Discounted Future Net Cash Flows

	Millions of Dollars								
	Consolidated Operations			Equity Affiliates			Total		
	2002	2001	2000	**2002**	2001	2000	**2002**	2001	2000
Discounted future net cash flows at the beginning of the year	**$ 8,995**	18,782	6,205	**996**	1,635	—	**9,991**	20,417	6,205
Changes during the year									
Revenues less production and transportation costs for the year	**(5,271)**	(4,283)	(4,592)	**(177)**	(6)	—	**(5,448)**	(4,289)	(4,592)
Net change in prices, and production and transportation costs	**15,566**	(14,668)	10,396	**2,734**	(1,552)	—	**18,300**	(16,220)	10,396
Extensions, discoveries and improved recovery, less estimated future costs	**1,284**	757	1,817	**22**	—	2,402	**1,306**	757	4,219
Development costs for the year	**2,151**	1,495	995	**467**	420	135	**2,618**	1,915	1,130
Changes in estimated future development costs	**(1,790)**	(1,011)	(775)	**(108)**	(17)	(135)	**(1,898)**	(1,028)	(910)
Purchases of reserves in place, less estimated future costs	**22,161**	130	8,168	**4,781**	—	—	**26,942**	130	8,168
Sales of reserves in place, less estimated future costs	**(563)**	(9)	(1,037)	**(16)**	—	—	**(579)**	(9)	(1,037)
Revisions of previous quantity estimates*	**(185)**	15	1,750	**(712)**	38	—	**(897)**	53	1,750
Accretion of discount	**1,540**	2,877	1,217	**177**	260	—	**1,717**	3,137	1,217
Net change in income taxes	**(15,726)**	4,909	(5,360)	**(1,957)**	218	(767)	**(17,683)**	5,127	(6,127)
Other	**—**	1	(2)	**—**	—	—	**—**	1	(2)
Total changes	**19,167**	(9,787)	12,577	**5,211**	(639)	1,635	**24,378**	(10,426)	14,212
Discounted future net cash flows at year-end	**$ 28,162**	8,995	18,782	**6,207**	996	1,635	**34,369**	9,991	20,417

**Includes amounts resulting from changes in the timing of production.*

- The net change in prices, and production and transportation costs is the beginning-of-the-year reserve-production forecast multiplied by the net annual change in the per-unit sales price, and production and transportation cost, discounted at 10 percent.
- Purchases and sales of reserves in place, along with extensions, discoveries and improved recovery, are calculated using production forecasts of the applicable reserve quantities for the year multiplied by the end-of-the-year sales prices, less future estimated costs, discounted at 10 percent.
- The accretion of discount is 10 percent of the prior year's discounted future cash inflows, less future production, transportation and development costs.
- The net change in income taxes is the annual change in the discounted future income tax provisions.

5-Year Financial Review (Millions of Dollars Except as Indicated)

	2002	2001	2000	1999	1998
Selected Income Data					
Sales and other operating revenues (includes excise taxes on petroleum products sales)	**$56,748**	24,892	22,155	14,988	12,853
Total revenues	**$57,224**	25,044	22,539	15,260	13,145
Income from continuing operations	**$ 714**	1,611	1,848	604	228
Effective income tax rate	**67.0%**	50.5	50.7	48.7	44.0
Net income (loss)	**$ (295)**	1,661	1,862	609	237
Selected Balance Sheet Data					
Current assets	**$10,903**	6,498	2,752	2,914	2,497
Properties, plants and equipment (net)	**$43,030**	22,133	14,644	10,950	10,451
Total assets	**$76,836**	35,217	20,509	15,201	14,216
Current liabilities	**$12,816**	4,821	3,502	2,531	2,142
Long-term debt	**$18,917**	8,610	6,622	4,271	4,106
Total debt	**$19,766**	8,654	6,884	4,302	4,273
Mandatorily redeemable preferred securities of trust subsidiaries	**$ 350**	650	650	650	650
Other minority interests	**$ 651**	5	1	1	1
Common stockholders' equity	**$29,517**	14,340	6,093	4,549	4,219
Percent of total debt to capital*	**39%**	37	51	45	47
Current ratio	**.9**	1.3	.8	1.2	1.2
Selected Statement of Cash Flows Data					
Net cash provided by operating activities from continuing operations	**$ 4,767**	3,529	3,984	1,934	1,587
Net cash provided by operating activities	**$ 4,969**	3,562	4,014	1,941	1,630
Capital expenditures and investments**	**$ 4,388**	3,016	2,017	1,686	2,045
Cash dividends paid on common stock	**$ 684**	403	346	344	353
Other Data					
Per average common share outstanding					
Income from continuing operations					
Basic	**$ 1.48**	5.50	7.26	2.39	.88
Diluted	**$ 1.47**	5.46	7.21	2.37	.88
Net income (loss)					
Basic	**$ (.61)**	5.67	7.32	2.41	.92
Diluted	**$ (.61)**	5.63	7.26	2.39	.91
Cash dividends paid on common stock	**$ 1.48**	1.40	1.36	1.36	1.36
Common stockholders' equity per share (book value)	**$ 43.56**	37.52	23.86	17.94	16.74
Common shares outstanding at year-end (in millions)	**677.6**	382.2	255.4	253.6	252.0
Average common shares outstanding (in millions)					
Basic	**482.1**	293.0	254.5	252.8	258.3
Diluted	**485.5**	295.0	256.3	254.4	260.2
Common stockholders at year-end (in thousands)	**60.9**	54.7	49.2	51.7	56.0
Employees at year-end (in thousands)	**57.3**	38.7	12.4***	15.9	17.3

**Capital includes total debt, mandatorily redeemable preferred securities of trust subsidiaries, other minority interests and common stockholders' equity.*

***Excludes acquisitions, net of cash acquired.*

****Excludes 3,400 employees who were under contract to Chevron Phillips Chemical Company LLC (CPChem) from July 1, 2000, through December 31, 2000. Effective January 1, 2001, those employees became employees of CPChem.*

5-Year Operating Review

E&P	**2002**	2001	2000	1999	1998
	Thousands of Barrels Daily				
Net Crude Oil Production					
United States	**371**	373	241	50	62
Norway	**157**	117	114	99	99
United Kingdom	**39**	19	25	34	22
Canada	**13**	1	6	7	7
Other areas	**67**	51	51	41	32
Total consolidated	**647**	561	437	231	222
Equity affiliates	**35**	2	—	—	—
	682	563	437	231	222
Net Natural Gas Liquids Production					
United States	**32**	26	20	2	3
Norway	**6**	5	5	4	5
United Kingdom	**2**	2	2	2	2
Canada	**4**	—	1	1	1
Other areas	**2**	2	1	2	2
	46	35	29	11	13
Net Natural Gas Production*	Millions of Cubic Feet Daily				
United States	**1,103**	917	928	950	968
Norway	**171**	130	136	126	190
United Kingdom	**424**	178	214	220	197
Canada	**165**	18	83	91	97
Other areas	**180**	92	33	6	—
Total consolidated	**2,043**	1,335	1,394	1,393	1,452
Equity affiliates	**4**	—	—	—	—
	2,047	1,335	1,394	1,393	1,452

Represents quantities available for sale. Excludes gas equivalent of natural gas liquids shown above.

	Thousands of Barrels Daily				
Syncrude Production	**8**	—	—	—	—
Net Oil and Gas Acreage	Millions of Acres				
United States	**7**	5	5	3	3
International	**94**	21	29	33	31
Total consolidated	**101**	26	34	36	34
Equity affiliates	**1**	—	—	—	—
	102	26	34	36	34
Oil and Gas Wells	Net Wells				
United States					
Oil	**3,561**	2,430	2,450	1,832	2,610
Gas and condensate	**7,601**	3,686	3,333	2,936	2,932
International					
Oil	**2,851**	134	178	740	764
Gas and condensate	**3,588**	99	99	396	354
Total consolidated	**17,601**	6,349	6,060	5,904	6,660
Equity affiliates	**938**	22	—	—	—
	18,539	6,371	6,060	5,904	6,660
Well Completions					
United States					
Exploratory	**39**	68	50	2	10
Development	**346**	393	269	122	126
International					
Exploratory	**32**	4	18	15	4
Development	**45**	11	17	27	34
Total consolidated	**462**	476	354	166	174
Equity affiliates	**54**	20	—	—	—
	516	496	354	166	174

Midstream	**2002**	2001	2000	1999	1998
	Thousands of Barrels Daily				
Natural Gas Liquids Extracted	**156**	120	131	156	157
R&M					
Refinery Operations					
United States					
Rated crude oil capacity	**1,829***	732**	335	330	310
Crude oil runs	**1,661**	686	303	326	311
Refinery production	**1,847**	795	365	385	366
International					
Rated crude oil capacity	**195***	22**	—	—	—
Crude oil runs	**152**	20	—	—	—
Refinery production	**164**	19	—	—	—
Petroleum Products Sales* **					
United States					
Automotive gasoline	**1,147**	465	267	263	266
Distillates	**392**	170	107	100	106
Aviation fuels	**185**	78	41	36	31
Other products	**372**	220	50	34	26
	2,096	933	465	433	429
International	**162**	10	43	37	36
	2,258	943	508	470	465

The weighted-average crude oil capacity for the period included the refineries added from the merger with Conoco on August 30, 2002. Actual capacity at December 31, 2002 was 2,166 thousand barrels per day in the United States and 440 thousand barrels per day from international operations (including ConocoPhillips' share of equity affiliates).

***The weighted-average crude oil capacity for the period included the refineries acquired in the Tosco acquisition on September 14, 2001. Actual capacity at December 31, 2001, was 1,656 thousand barrels per day in the United States, and 72 thousand barrels per day from foreign operations (Ireland).*

****Excludes spot market sales.*

Chemicals*

Production	Millions of Pounds				
Ethylene	**3,217**	3,291	3,574	3,262	3,148
Polyethylene	**2,004**	1,956	2,230	2,590	2,290
Styrene**	**887**	456	404	n/a	n/a
Normal alpha olefins	**592**	563	293	n/a	n/a

Beginning July 1, 2000, ConocoPhillips' Chemicals segment consists mainly of its 50 percent equity interest in Chevron Phillips Chemical Company LLC.

***Production limited in 2001 due to a fire at the St. James, Louisiana, facility in February 2001. Capacity was restored in October 2001.*

2002 ConocoPhillips Board of Directors


Richard H. Auchinleck


Norman R. Augustine


David L. Boren


Kenneth M. Duberstein


Archie W. Dunham


Ruth R. Harkin

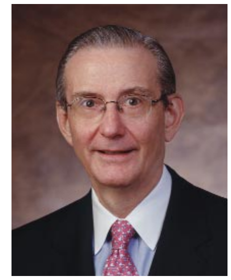

Larry D. Horner


Charles C. Krulak


Frank A. McPherson


J.J. Mulva


William K. Reilly


William R. Rhodes


J. Stapleton Roy


Randall L. Tobias


Victoria J. Tschinkel


Kathryn C. Turner

Richard H. Auchinleck, 51, president and CEO of Gulf Canada Resources Limited from February 1998 to June 2001. Chief operating officer of Gulf Canada from July 1997 to February 1998. CEO for Gulf Indonesia Resources Limited from September 1997 to February 1998. Lives in Calgary, Alberta, Canada. (5)

Norman R. Augustine, 67, chairman of the executive committee of the board of directors of Lockheed Martin Corporation since August 1997. Chairman of the board of directors of Lockheed Martin Corporation from August 1997 through March 1998. CEO of Lockheed Martin from January 1996 through July 1997. Also a director of The Black & Decker Corporation, The Procter & Gamble Company and Lockheed Martin Corporation. Lives in Potomac, Md. (3, 4)

David L. Boren, 61, president of the University of Oklahoma since 1994. Former U.S. senator from Oklahoma and former governor of Oklahoma. Also a director of AMR Corporation, Texas Instruments Incorporated and Torchmark Corporation. Lives in Norman, Okla. (5)

Kenneth M. Duberstein, 58, chairman and CEO of the Duberstein Group, a strategic planning and consulting company, since 1989. Served as White House chief of staff and deputy chief of staff to President Ronald Reagan and deputy undersecretary of Labor during the Ford administration. Sits on the board of governors for the NASD and the American Stock Exchange. Also a director of The Boeing Company, Fannie Mae, Fleming Companies, Inc. and The St. Paul Companies, Inc. Lives in Washington, D.C. (1, 2, 4)

Archie W. Dunham, 64, chairman of the board of directors. Previously, chairman of the board, president and CEO of Conoco Inc. from 1999 to 2002. Joined Conoco in 1966 and became president and CEO in 1996 and chairman of the board in 1999. Serves as chairman of the National Association of Manufacturers. Also a director of the American Petroleum Institute, a past chairman of the National Petroleum Council and the U.S. Energy Association, and a member of The Business Council and The Business Roundtable. Serves as a director of the Memorial Hermann Healthcare System, chairman and trustee of the Houston Grand Opera, and trustee of the Smithsonian Institution and the George Bush Presidential Library. Also a director of Louisiana-Pacific Corporation, Phelps Dodge Corporation and Union Pacific Corporation. (2)

Ruth R. Harkin, 58, senior vice president, international affairs and government relations, for United Technologies Corporation and chair of United Technologies International, UTC's international representation arm, since June 1997. Lives in Alexandria, Va. (1)

Larry D. Horner, 68, chairman of Pacific USA Holdings Corporation from August 1994 to June 2001. Past chairman and CEO of KPMG Peat Marwick. Also a director of Atlantis Plastics, Inc., Technical Olympic USA, Inc. and UTStarcom, Inc. Lives in San Jose del Cabo, BCS, Mexico. (1)

Charles C. Krulak, 61, chairman and CEO of MBNA Europe Bank Limited since January 2001. During his 35-year career in the Marine Corps, Gen. Krulak served two tours of duty in Vietnam and rose through several command and staff positions to become commandant of the Marine Corps and a member of the Joint Chiefs of Staff, June 1995 to September 1999. Holds the Defense Distinguished Service medal, the Silver Star, the Bronze Star with Combat "V" and two gold stars, the Purple Heart with gold star and the Meritorious Service medal. Lives in Chester, Chesire, United Kingdom. (3, 4)

Frank A. McPherson, 69, chairman and CEO of Kerr-McGee Corporation until 1997, having held those positions since 1983. Also a director of BOK Financial Corporation, Tri-Continental Corporation and the Seligman Group of Mutual Funds. Lives in Oklahoma City, Okla. (1, 2)

J.J. Mulva, 56, president and CEO of ConocoPhillips. Previously, chairman of the board of directors and CEO of Phillips Petroleum Company since October 1999. Was vice chairman, president and CEO in 1999, and president and chief operating officer from 1994 to 1999. Joined Phillips in 1973; elected to board in 1994. Also a director of the American Petroleum Institute and member of The Business Council and The Business Roundtable. Serves as a trustee of the Boys and Girls Clubs of America. (2)

William K. Reilly, 63, president and CEO of Aqua International Partners, an investment group that finances water improvements in developing countries, since June 1997. Also a director of E.I. du Pont de Nemours and Company, Ionics, Incorporated and Royal Caribbean Cruises Ltd. Lives in San Francisco, Calif. (5)

William R. Rhodes, 67, senior vice chairman of Citigroup, Inc. since December 2001. Vice chairman of Citigroup, Inc. from May 1999 to December 2001. Vice chairman of Citicorp/Citibank from July 1991 to May 1999. Lives in New York, N.Y. (3)

J. Stapleton Roy, 67, managing director of Kissinger Associates, Inc. since January 2001. Assistant secretary of State for intelligence and research from 1999 to 2000. He attained the highest rank in the Foreign Service, career ambassador, while serving as ambassador to Singapore, Indonesia and the People's Republic of China. Also a director of Freeport-McMoRan Copper & Gold Inc. Lives in Bethesda, Md. (1)

Randall L. Tobias, 61, chairman emeritus of Eli Lilly and Company since January 1999. Chairman of the board of directors and CEO of Eli Lilly and Company from July 1993 through December 1998. Also a director of Kimberly-Clark Corporation, Knight-Ridder, Inc., Interactive Intelligence, Inc. and Windrose Medical Properties Trust. Lives in Indianapolis, Ind. (2, 3, 4)

Victoria J. Tschinkel, 55, director of the Florida Nature Conservancy since January 2003. Senior environmental consultant to Landers & Parsons, a Tallahassee law firm, from 1987 to 2002. Former secretary of the Florida Department of Environmental Regulation. Lives in Tallahassee, Fla. (2, 5)

Kathryn C. Turner, 55, chairperson and CEO of Standard Technology, Inc., an engineering and manufacturing firm she founded in 1985. Also a director of Carpenter Technology Corporation, Schering-Plough Corporation and Tribune Company. Lives in Bethesda, Md. (1)

(1) Member of Audit and Compliance Committee (2) Member of Executive Committee (3) Member of Compensation Committee (4) Member Directors' Affairs Committee (5) Member Public Policy Committee

Officers (As of March 24, 2003)

Archie W. Dunham, Chairman

J.J. Mulva, President and Chief Executive Officer

William B. Berry, Executive Vice President, Exploration and Production

John A. Carrig, Executive Vice President, Finance, and Chief Financial Officer

Philip L. Frederickson, Executive Vice President, Commercial

John E. Lowe, Executive Vice President, Planning and Strategic Transactions

Robert E. McKee III, Executive Vice President

Jim W. Nokes, Executive Vice President, Refining, Marketing, Supply and Transportation

E.L. Batchelder, Senior Vice President and Chief Information Officer

Rick A. Harrington, Senior Vice President, Legal, and General Counsel

Thomas C. Knudson, Senior Vice President, Government Affairs and Communications

Rand C. Berney, Vice President and Controller

Joseph C. High, Vice President, Human Resources

Robert A. Ridge, Vice President, Health, Safety and Environment

J.W. Sheets, Vice President and Treasurer

Richard A. Sherry, Vice President, Tax

Steve L. Scheck, General Auditor and Chief Ethics Officer

E. Julia Lambeth, Corporate Secretary

Ben J. Clayton, Tax Administration Officer

Steve L. Wilson, Assistant Tax Administration Officer

Donna L. Franklin, Assistant Controller

C. Douglas Johnson, Assistant Controller

J.E. Durbin, Assistant Treasurer

Frances M. Vallejo, Assistant Treasurer

Operational and Functional Organizations

Stephen R. Barham, President, Transportation

Sigmund L. Cornelius, Vice President, Upstream Business Development

Dodd W. DeCamp, Vice President, Exploration

Gregory J. Goff, President, Europe and Asia Pacific

Mark R. Harper, President, Wholesale Marketing

David B. Holthe, President, Retail Marketing

Andrew J. Kelleher, President, Americas Supply and Trading

Carin S. Knickel, President, Specialty Businesses

James R. Knudsen, Vice President, Upstream Technology

Ryan M. Lance, Vice President, Lower 48

James D. McColgin, President, U.S.A. Lower 48 and Latin America

Henry I. McGee III, President, Middle East & Africa

Kevin O. Meyers, President, Alaska

Thomas J. Nimbley, President, Refining

George W. Paczkowski, Vice President, Downstream Technology

Richard W. Severance, Senior Vice President, Strategy, Optimization and Business Development

J. Michael Stice, President, Gas and Power

Henry W. Sykes, President, Canada

Steven M. Theede, President, Europe, Russia and Caspian

Glossary

Appraisal Drilling: Drilling carried out following the discovery of a new field to determine the physical extent, amount of reserves and likely production rate of the field.

Aromatics: Hydrocarbons that have at least one benzene ring as part of their structure. Aromatics include benzene, toluene and xylenes.

Barrels of Oil Equivalent (BOE): A term used to quantify oil and natural gas amounts using the same measurement. Gas volumes are converted to barrels on the basis of energy content. 6,000 cubic feet of gas equals one barrel of oil.

Catalyst: Substance that increases the rate of a chemical reaction between other substances.

Coke: A solid carbon product produced by thermal cracking.

Commercial Field: An oil or natural gas field that, under existing economic and operating conditions, is judged to be capable of generating enough revenues to exceed the costs of development.

Condensate: Light liquid hydrocarbons. As they exist in nature, condensates are produced in natural gas mixtures and separated from the gases by absorption, refrigeration and other extraction processes.

Cyclohexane: The cyclic form of hexane used as a raw material in the manufacture of nylon.

Deepwater: Water depth of at least 1,000 feet.

Distillates: The middle range of petroleum liquids produced during the processing of crude oil. Products include diesel fuel, heating oil and kerosene.

Downstream: Refining, marketing and transportation operations.

Ethylene: Basic chemical used in the manufacture of plastics (such as polyethylene), antifreeze and synthetic fibers.

Exploitation: Focused, integrated effort to extend the economic life, production and reserves of an existing field.

Feedstock: Crude oil, natural gas liquids, natural gas or other materials used as raw ingredients for making gasoline, other refined products or chemicals.

Fluid Catalytic Cracking Unit: A refinery unit that cracks large hydrocarbon molecules into lighter, more valuable products such as gasoline components, propanes, butanes and pentanes, using a powdered catalyst that is maintained in a fluid state by use of hydrocarbon vapor, inert gas, or steam.

Gas-to-Liquids (GTL): A process that converts natural gas to clean liquid fuels.

Hydrocarbons: Organic chemical compounds of hydrogen and carbon atoms that form the basis of all petroleum products.

Improved Recovery: Technology for increasing or prolonging the productivity of oil and gas fields. This is a special field of activity and research in the oil and gas industry.

Liquefied Natural Gas (LNG): Gas, mainly methane, that has been liquefied in a refrigeration and pressure process to facilitate storage or transportation.

Liquids: An aggregate of crude oil and natural gas liquids; also known as hydrocarbon liquids.

Margins: Difference between sales prices and feedstock costs, or in some instances, the difference between sales prices and feedstock and manufacturing costs.

Midcycle Returns: Midcycle returns are calculated assuming prices of $20 per barrel for West Texas Intermediate crude oil, $3.25 per thousand cubic feet of gas at Henry Hub, and $3.25 per barrel Gulf Coast crack spread for refined products.

Midstream: Natural gas gathering, processing and marketing operations.

Natural Gas Liquids (NGL): A mixed stream of ethane, propane, butanes and pentanes that is split into individual components. These components are used as feedstocks for refineries and chemical plants.

Olefins: Basic chemicals made from oil or natural gas liquids feedstocks; commonly used to manufacture plastics and gasoline. Examples are ethylene and propylene.

Paraxylene: An aromatic compound used to make polyester fibers and plastic soft drink bottles.

Polyethylene: Plastic made from ethylene used in manufacturing products including trash bags, milk jugs, bottles and pipe.

Polypropylene: Basic plastic derived from propylene used in manufacturing products including fibers, films and automotive parts.

Reservoir: A porous, permeable sedimentary rock formation containing oil and/or natural gas, enclosed or surrounded by layers of less permeable or impervious rock.

Spot Sale: In the petroleum industry, the sale of bulk or large quantities of raw materials or products under terms based on publicly available market quotations that are subject to constant change.

Styrene: A liquid hydrocarbon used in making various plastics by polymerization or copolymerization.

Syncrude: Synthetic crude oil derived by upgrading bitumen extractions from mine deposits of oil sands.

S Zorb™: The name for ConocoPhillips' proprietary sulfur removal technologies for gasoline and diesel fuel. The technologies remove sulfur to ultra-low levels while preserving important product characteristics and consuming minimal amounts of hydrogen, a critical element in refining.

Tension-Leg Platform: A semisubmersible drilling platform held in position by multiple cables anchored to the ocean floor.

Three-Dimensional Seismic: Three-dimensional images created by bouncing sound waves off underground rock formations; used by oil companies to determine the best places to drill for hydrocarbons.

Throughput: The average amount of raw material that is processed in a given period by a facility, such as a natural gas processing plant, an oil refinery or a petrochemical plant.

Total Recordable Rate: A metric for evaluating safety performance calculated by multiplying the total number of recordable cases by 200,000 then dividing by the total number of work hours.

Upstream: Oil and natural gas exploration and production activities.

Wildcat Drilling: Exploratory drilling performed in an unproven area, far from producing wells.

Stockholder Information

Annual Meeting
ConocoPhillips' annual meeting of stockholders will be held at the following time and place:

May 6, 2003; 10:30 a.m.
Omni Houston Hotel Westside, 13210 Katy Freeway, Houston, Texas

Notice of the meeting and proxy materials are being sent to all stockholders.

Direct Stock Purchase and Dividend Reinvestment Plan
ConocoPhillips' Investor Services Program is a direct stock purchase and dividend reinvestment plan that offers stockholders a convenient way to buy additional shares and reinvest their common stock dividends. Purchases of company stock through direct cash payment are commission-free. For details contact:

Mellon Investor Services, L.L.C.
P.O. Box 3336
South Hackensack, NJ 07606
Toll-free number: 1-800-356-0066

Information Requests
For information about dividends and certificates, or to request a change of address, stockholders may contact:

Mellon Investor Services, L.L.C.
P.O. Box 3315
South Hackensack, NJ 07606
Toll-free number: 1-800-356-0066
Outside the U.S.: (201) 329-8660
TDD: 1-800-231-5469
Outside the U.S.: (201) 329-8345
Fax: (201) 329-8967
Internet: *www.melloninvestor.com*

Personnel in the following office also can answer investors' questions about the company:

ConocoPhillips Investor Relations
375 Park Avenue, Suite 3702
New York, NY 10152
(212) 207-1996
c.c.reasor@conocophillips.com

Internet Web Site: *www.conocophillips.com*
The site includes the Investor Information Center, which features news releases and presentations to securities analysts; copies of ConocoPhillips' Annual Report and Proxy Statement; reports to the U.S. Securities and Exchange Commission; and data on ConocoPhillips' health, safety and environmental performance. Other Web sites with information on topics in this annual report include:

www.fuelstechnology.com
www.cpchem.com
www.defs.com
www.phillips66.com
www.conoco.com
www.76.com

Form 10-K and Annual Reports
Copies of the Annual Report on Form 10-K, as filed with the U.S. Securities and Exchange Commission, are available free by calling (918) 661-3700, making a request on the company's Web site, or writing:

ConocoPhillips - 2002 Form 10-K
B-41 Adams Building
411 South Keeler Ave.
Bartlesville, OK 74004

Additional copies of this annual report may be obtained by calling (918) 661-3700, or writing:

ConocoPhillips - 2002 Annual Report
B-41 Adams Building
411 South Keeler Ave.
Bartlesville, OK 74004

Principal Offices
600 North Dairy Ashford
Houston, TX 77079

1013 Centre Road
Wilmington, DE 19805-1297

Stock Transfer Offices/Registrars
Mellon Investor Services, L.L.C.
Overpeck Centre
85 Challenger Road
Ridgefield Park, NJ 07660

Computershare Trust Company of Canada
100 University Ave.
Toronto, Ontario
Canada M5J 2Y1

Compliance and Ethics
For guidance, or to express concerns or ask questions about compliance and ethics issues, call ConocoPhillips' Ethics Helpline toll-free: 1-877-327-2272, available 24 hours a day, seven days a week. The ethics office also may be contacted via e-mail at: *ethics@conocophillips.com,* or by writing:

Attn: Corporate Ethics Office
Marland 2142
600 N. Dairy Ashford
Houston, TX, U.S.A. 77079-1175

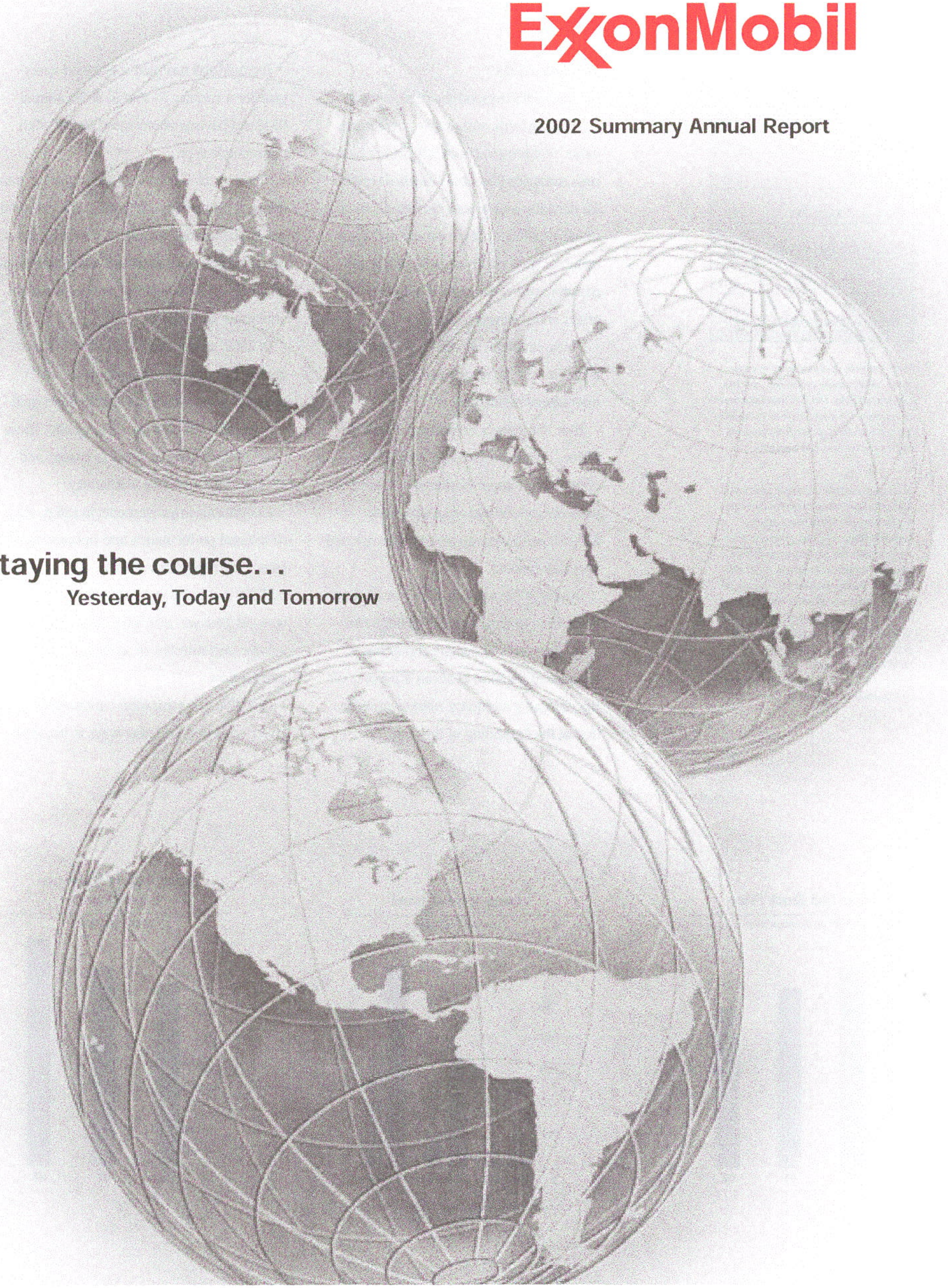
www.conocophillips.com

ConocoPhillips

Printed on recycled paper

ExxonMobil

2002 Summary Annual Report



Staying the course...

Yesterday, Today and Tomorrow

To Our Shareholders

Inside

Letter to Shareholders 2

Technology 4

Upstream 6

Downstream 14

Chemical 20

Coal and Minerals 23

Corporate Responsibility 24

Financial Summary 28

Investor Information 39

Note: The term *upstream* refers to exploration, development, production, gas and power marketing, and U.S. coal businesses or activities. *Downstream* refers to the refining and marketing of petroleum products such as motor fuels and lubricants.

Projections, targets, estimates and business plans in this report are forward-looking statements. Actual future results, including efficiency gains, cost reductions, project dates and capacities, production rates and resource recoveries, could differ materially due to, for example, changes in market conditions affecting the oil and gas industry; the outcome of commercial negotiations; unforeseen technical difficulties; political events and disturbances; and other factors discussed under the caption "Factors Affecting Future Results" in Item 1 of ExxonMobil's most recent Form 10-K.

Dear Shareholder:

ExxonMobil's overarching objective is to create long-term, sustainable shareholder value. We remain committed to the business strategies that have delivered results for decades: investment discipline, operational excellence, development and application of state-of-the-art technology, and maintenance of the highest standards of ethics and business integrity.

These strategies served us well in 2002, a year in which we saw particularly strong operational performance.

Your company's net income was $11.5 billion, despite a challenging industry environment in our businesses. Cash flow from operations and asset sales was $24 billion, and return on capital employed was 13.5 percent.

During 2002, we distributed more than $10 billion to shareholders through dividend payments and share repurchases, representing a total of about 4 percent of the company's (equity) market capitalization at the beginning of the year.

ExxonMobil has paid a dividend every year for a century — and in 2002, annual dividend payments increased for the 20th consecutive year.

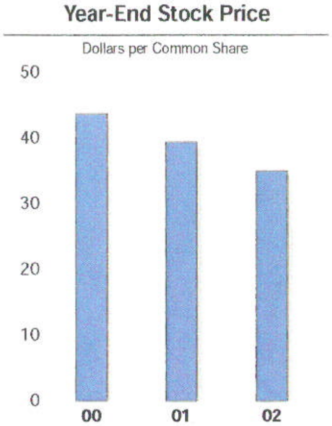
Our approach of maintaining rigorous standards of investment discipline has consistently delivered superior returns. It demonstrates to our shareholders that we are using their capital wisely and are creating long-term sustainable value and growth.

In 2002, we invested $14 billion in the growth of our business, and substantial progress was made in advancing our significant portfolio of high-quality projects. These projects underpin our plans to sustain and improve ExxonMobil's profitability.

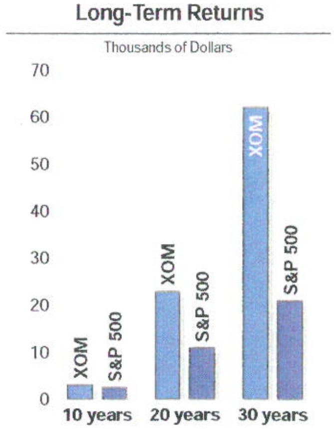
Continuous improvements in safety, environmental performance and operational efficiency are vitally important to our success. In 2002, our industry-leading safety record was our best yet, and we further reduced the volume and number of spills from our marine fleet.

Our global organization continued to lower costs and find new ways to improve

Year-End Stock Price

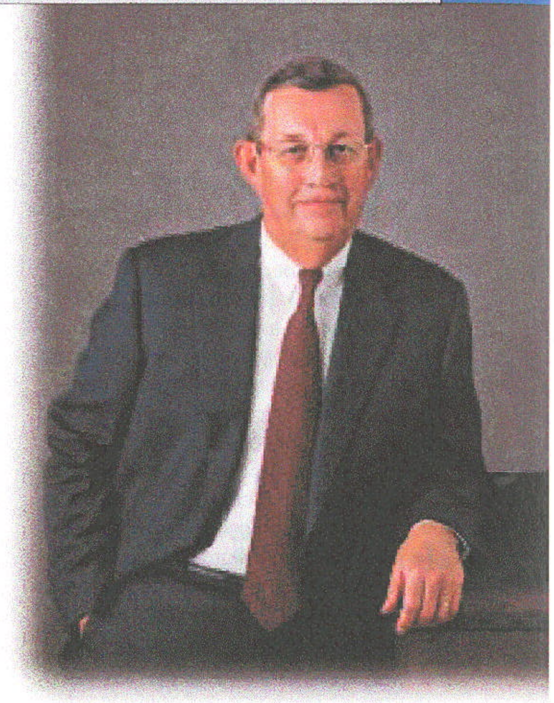


Long-Term Returns



Value of $1,000 invested over 10, 20 and 30 years, with dividends reinvested

Capital and Exploration Expenditures



the efficiency of our operations. We experienced one of our best years in facilities reliability. And more than $1 billion in cost efficiencies were delivered — bringing the total since the implementation of the merger to $5 billion.

These achievements in financial results, safety, environmental improvement and cost reduction have come about due to the skill, dedication and high personal standards of the thousands of ExxonMobil employees around the world. They continue to be the greatest strength of your company.

Technology also plays a critical role in our success and is a key factor that distinguishes ExxonMobil. While we have continued to pursue research in support of our existing businesses, a significant portion of our effort is focused on developing proprietary breakthrough technology that will have a significant and lasting benefit to the corporation.

In November of last year, we announced ExxonMobil's participation in a partnership with other global companies and with Stanford University. This partnership will undertake fundamental research to develop and commercialize technologies to substantially reduce greenhouse-gas emissions. Our participation in this project continues our long history of supporting climate research and helping advance next-generation technological innovations.

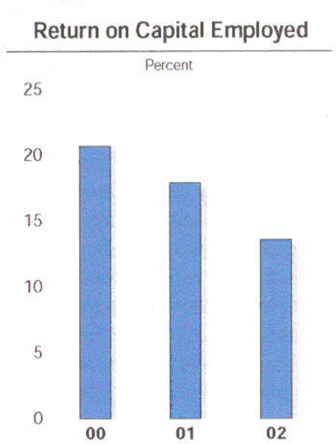
Recent events have reinforced the importance of business ethics and integrity, which are fundamental to how we have long operated at ExxonMobil. We manage the business for sustainable long-term results through a straightforward business model. We want our results to be clear and readily understood by shareholders. This company has a long history of leadership in corporate governance, and we continue to take steps to maintain that leadership position.

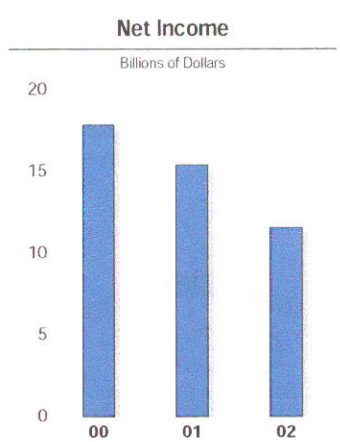
I firmly believe that these many strengths — combined with strong consumer demand for our products and abundant resources for supply — uniquely position ExxonMobil to take advantage of what we expect to be a very promising future in our industry. Both innovation and disciplined execution will be essential elements for success. The companies that endure and prosper will be those that can look beyond short-term fluctuations and stay focused on long-term fundamentals.

We are steadfast in our commitment to this course.

Lee R. Raymond

Chairman and CEO





Technology

Technology: the competitive edge

ExxonMobil has a long-standing commitment to supporting technology that is unmatched in our industry. Our $631 million research and development program (2002) is aimed at providing in-house proprietary technologies that will lower investment and operating costs, expand our resource base, create new products and markets, and improve our operational, safety and environmental performance.

Our disciplined, cost-effective approach to technology development distinguishes us from our competitors. This approach involves developing proprietary next-generation technologies, conducting fundamental research that leads to technological breakthroughs, and executing a rigorous process for identifying and applying valuable third-party technologies.

ExxonMobil employs about 20,000 engineers and scientists, nearly 2,000 of whom hold PhDs in various disciplines.

During the past 11 years, ExxonMobil has been granted more than 10,000 U.S. patents, more than any of our competitors.

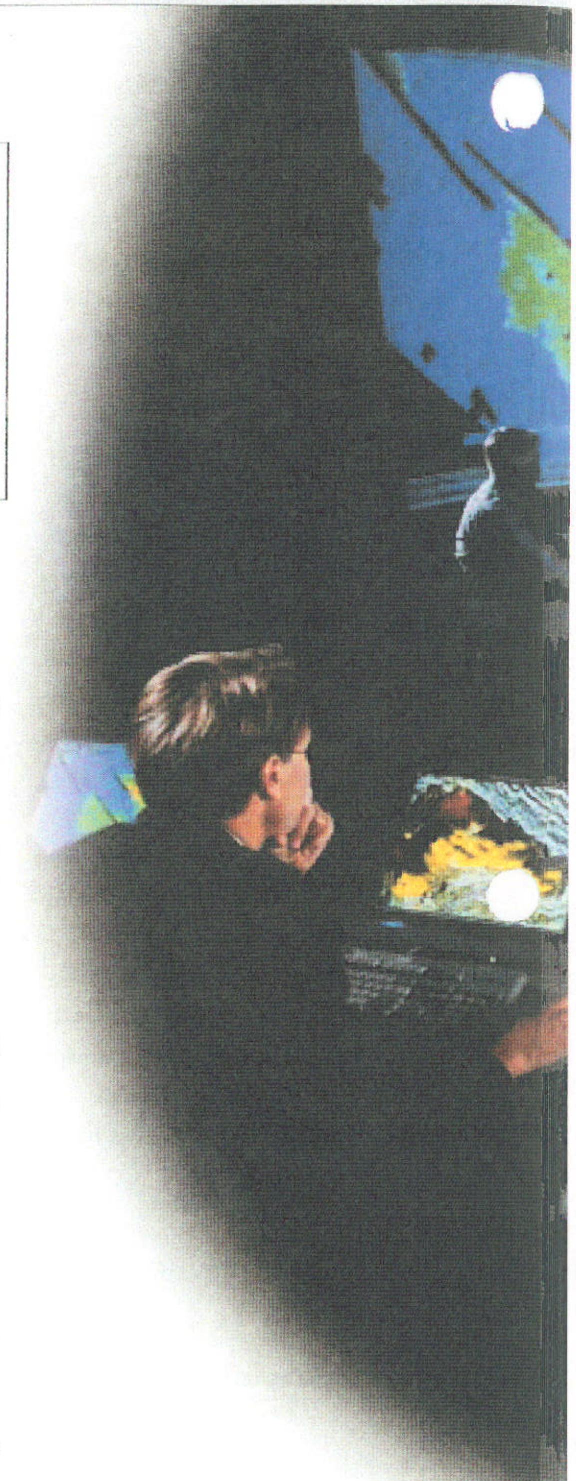
ExxonMobil conducts research and pursues technological solutions and breakthroughs across all our business lines — exploration, production, natural gas commercialization, refining and marketing, and chemical.

Research on non-seismic direct hydrocarbon detection has led to pending patents involving new technology for remotely detecting and imaging hydrocarbons from the earth's surface. This technology holds great promise for accurately assessing potential resources and reducing exploration risk.

Development teams at ExxonMobil's Doba project in Chad are utilizing state-of-the-art satellite data-transmission technology and our proprietary reservoir-modeling capability to identify the best locations for drilling new development wells. We are able to integrate the results from new development wells into reservoir-simulation models within a matter of hours. This capability enables development plans to be reassessed and new well plans to be engineered in a process that maximizes the economic value for ExxonMobil and the host government.

Development engineers are improving materials to lower the cost of long-distance pipelines. In addition, cost savings are being achieved in liquefied natural gas plants and ships through the capture of further economies of scale.

> ExxonMobil's technology leadership is largely about managing hydrocarbon molecules: from finding and simulating oil and gas flow in a field to maximize production at the lowest cost, to selecting the most profitable crude oils for our refineries, to making the catalysts that yield higher-quality gasolines and other petroleum and petrochemical products.



ExxonMobil's innovative partnerships with auto manufacturers are a key element in our strategy to maintain an industry-leading position in fuels and lubricants for advanced vehicle systems. In partnerships with industry leaders such as General Motors, Toyota, Ford, DaimlerChrysler and Caterpillar, we are advancing technologies for next-generation internal combustion systems, fuel cell systems, emissions controls, gasoline/electricity hybrid automobiles, and *Formula 1* fuels and lubricants.

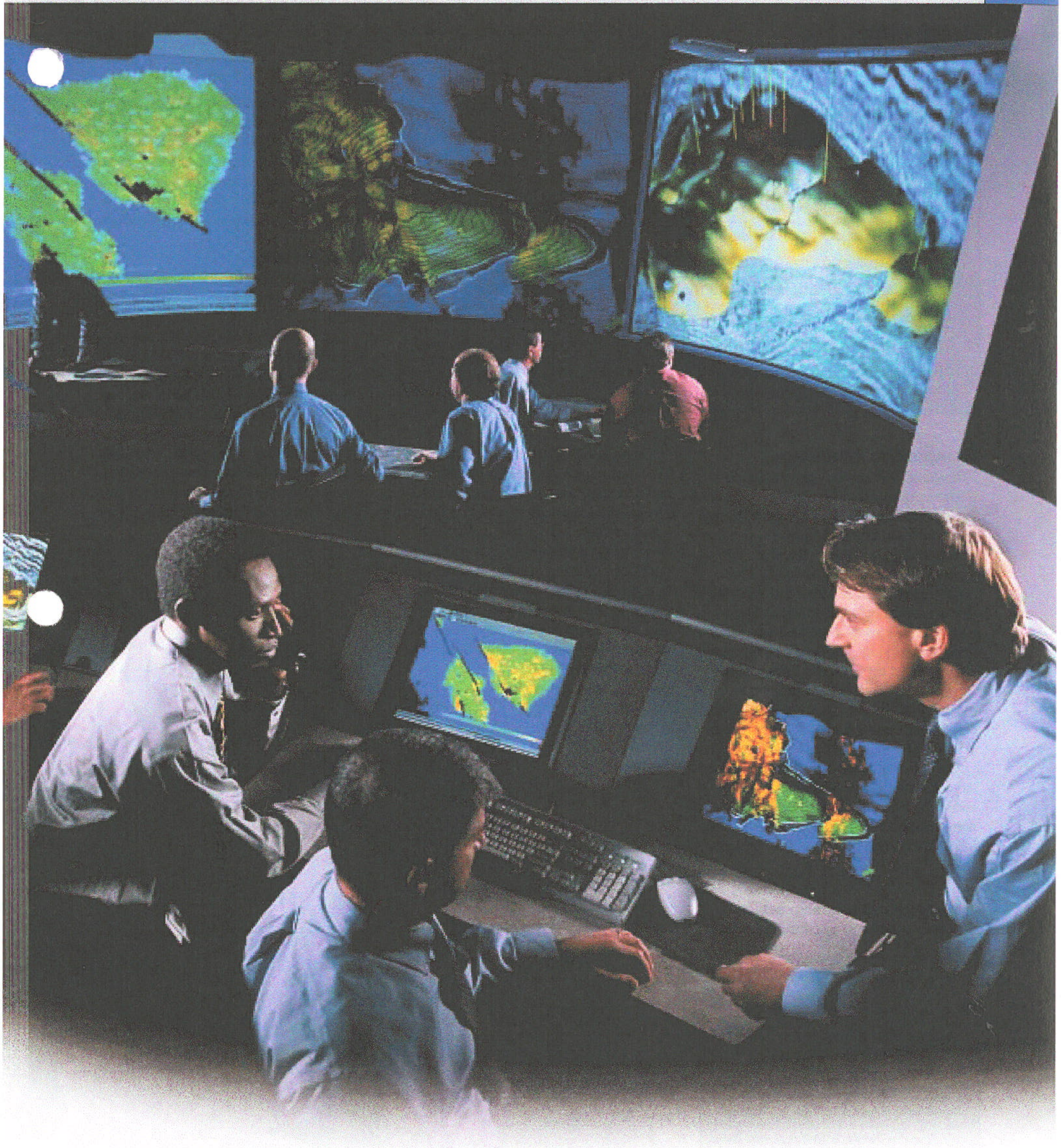
We are also a leader in the development and use of catalysts, the fundamental tools that increase the speed and effectiveness of chemical reactions. Our zeolite catalyst technology, for example, is revolutionizing the way we make basic chemicals. Metallocene catalyst technology is similarly revolutionizing polymers.

In addition to our in-house programs, ExxonMobil has made a significant commitment to a groundbreaking research effort at Stanford University. The company plans to invest $100 million over the next 10 years in the Global Climate and Energy Project (G-CEP).

This unprecedented alliance of scientific researchers and leading companies — including General Electric, Schlumberger and others — will work to find innovative and commercially viable step-out technologies that can substantially reduce greenhouse-gas emissions.

GCEP
Global Climate & Energy Project
STANFORD UNIVERSITY

G-CEP holds great promise for delivering new technologies that can give policymakers more options and help us continue to produce reliable and affordable energy while reducing environmental impacts in a cost-effective way.



ExxonMobil scientists in Houston analyze data
transmitted by satellite from oil fields in Chad.

Upstream

Quality portfolio and leading-edge technology yield strong returns	
Earnings	$9.6 billion
Return on average capital employed	22.3 percent
Capital and exploration expenditures	$10.4 billion
Liquids production (barrels/day)	2.5 million
Natural gas production available for sale (cu. ft./day)	10.5 billion
New resource additions (oil equivalent)	2.2 billion barrels
Proved reserves additions (oil equivalent)	1.9 billion barrels
Finding and development costs (Five-year average per oil-equivalent barrel)	$4.39

Competitive Advantage

ExxonMobil's world-class, geographically diverse upstream portfolio consists of 72 billion oil-equivalent barrels of oil and gas resources and activities in nearly 40 countries.

Large, highly profitable oil and gas operations in established areas, including North America, Europe, Asia Pacific and West Africa, are the foundation of this portfolio. These areas include long-life fields and have significant near-term potential as new opportunities are developed using existing infrastructure.

ExxonMobil also holds a strong position in the Caspian, Eastern Canada, the Middle East and Russia, as well as in the deep waters of West Africa and the Gulf of Mexico.

Our financial strength allows us to pursue all profitable opportunities. We continually invest in our existing assets to extend their economic life and have an industry-leading portfolio of more than 100 major new projects.

ExxonMobil's long-standing investment in leading-edge technology is unmatched in the industry and provides a sustainable competitive advantage. Technology underpins everything we do, from exploration, through development and production operations, to gas marketing. It allows us to maximize value by increasing recoverable resources, reducing costs and creating new markets. It serves us in countries where we have an established business presence and in emerging areas, where we are positioned to be the partner of choice.

ExxonMobil has an experienced, dedicated and diverse workforce of exceptional quality. Our functional organization allows us to establish priorities on a global basis, effectively leverage the transfer of technology and best practices, focus on operational excellence and efficiently deploy experienced people.

2002 Results

Upstream earnings of $9.6 billion were down from 2001, primarily due to lower natural gas prices.

Capital and exploration spending grew by $1.6 billion to $10.4 billion, reflecting significant new projects being implemented on schedule. Production increased by one percent, excluding the impact of OPEC quota restrictions. Ten major new projects were brought onstream, with targeted gross daily peak production of more than 490 thousand barrels of liquids (average ExxonMobil interest, 44 percent) and 230 million cubic feet of gas

ExxonMobil has upstream activities on every continent except Antarctica.

- Exploration and/or Production
- Major Oil & Gas Resource Additions
- Acreage Additions/Agreements
- Major Capital Development Projects Under Way

The term *resource* as well as references to the *resource base* and *recoverable resources* (other than historical production) in this report include discovered quantities of oil and gas that are not yet classified as proved reserves but that we believe will likely be developed in the future.

Proved reserve figures in this report include proved reserves from Syncrude tar sands operations in Canada, which are treated as mining operations in our Securities and Exchange Commission reports.

(average ExxonMobil interest, 42 percent).

Proved reserves additions totaled 1.9 billion oil-equivalent barrels and replaced 118 percent of reserves produced (excluding asset sales).

Additions to our resource base totaled 2.2 billion oil-equivalent barrels at a finding cost of 61 cents per barrel. Key resource additions came from Angola, Nigeria, Australia, Kazakhstan and North America.

An Extensive Portfolio of Opportunities

North America

ExxonMobil has the industry's largest portfolio of proved reserves and production in North America. Daily hydrocarbon production totaled more than 1 million barrels of liquids and 3.4 billion cubic feet of gas (ExxonMobil net interest). This represented about 38 percent of our worldwide production on an oil-equivalent basis.

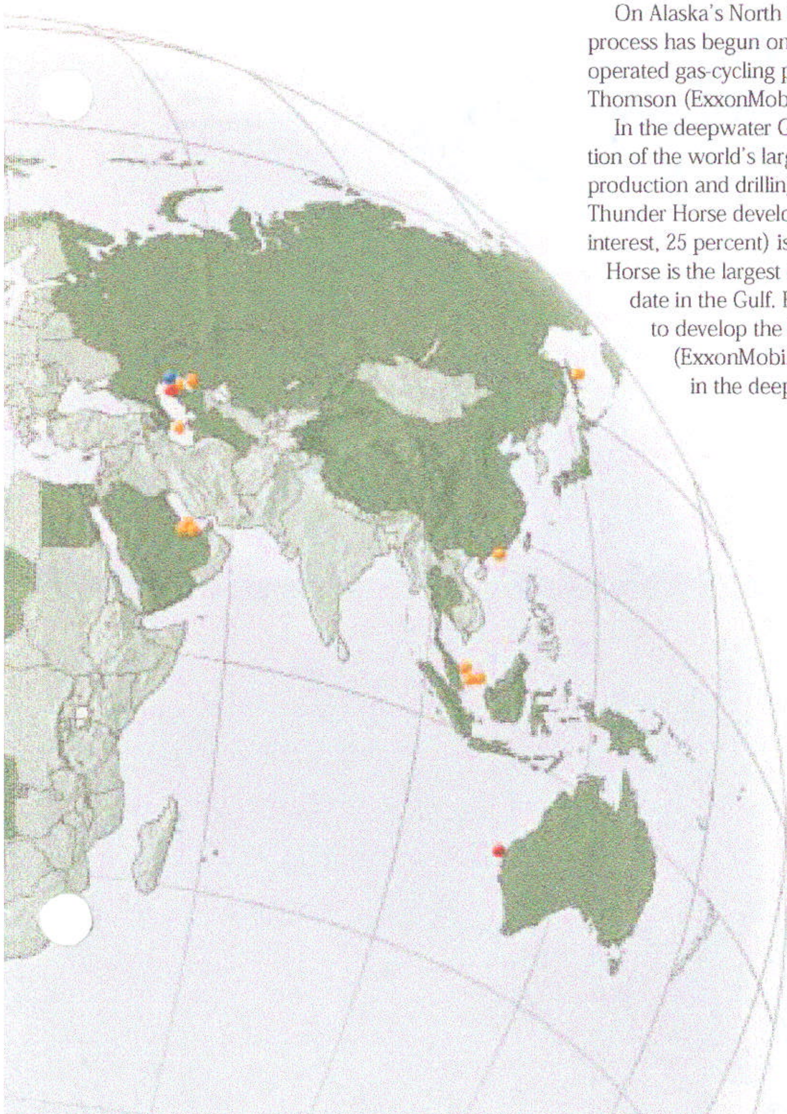
Strategies

- ❑ Maximize profitability of existing oil and gas production
- ❑ Identify and pursue all attractive exploration opportunities
- ❑ Invest in projects that deliver superior returns
- ❑ Capitalize on growing natural gas and power markets

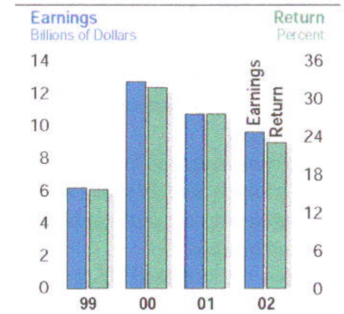
Upstream strategies are supported by an unparalleled commitment to technology. Superior execution of these strategies through our global functional organization distinguishes ExxonMobil from the competition.

On Alaska's North Slope, the permitting process has begun on the ExxonMobil-operated gas-cycling project at Point Thomson (ExxonMobil interest, 36 percent).

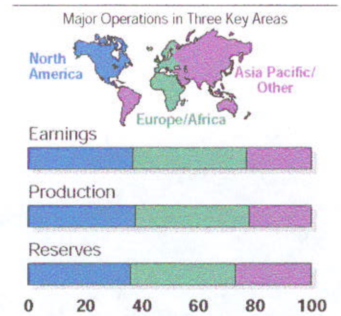
In the deepwater Gulf of Mexico, fabrication of the world's largest semisubmersible production and drilling vessel for the Thunder Horse development (ExxonMobil interest, 25 percent) is under way. Thunder Horse is the largest discovery made to date in the Gulf. Plans are progressing to develop the Llano discovery (ExxonMobil interest, 23 percent) in the deepwater Gulf of Mexico.



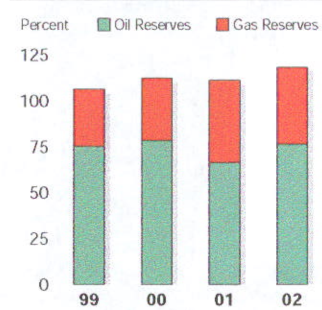
Earnings and Return on Capital Employed



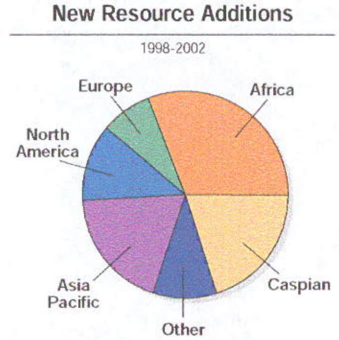
Global Portfolio



Proved Reserves Replacement



New Resource Additions



Upstream

A new well is drilled in the ExxonMobil-operated Waha field near Pecos, Texas. The field is part of the company's industry-leading production portfolio in the United States. Drilling represents more than one-third of worldwide upstream investment annually.

The second phase of the ExxonMobil-operated Mica development (ExxonMobil interest, 50 percent) was brought on production. Subsea wells are located 29 miles from the host production facilities, making Mica the longest subsea oil tieback in North America.

ExxonMobil acquired interests in 24 deepwater blocks and 10 shelf blocks, further strengthening our position in the Gulf's high-potential areas.

Onshore, we increased U.S. gas exploration with 11 (gross) successful wildcats.

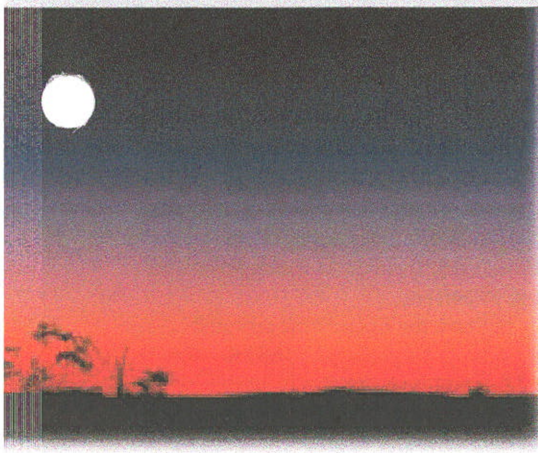
Through our wholly owned affiliate, ExxonMobil Canada Ltd., and our majority-owned affiliate, Imperial Oil Limited, ExxonMobil is the largest crude oil producer in Canada.

In Western Canada, expansion of the Cold Lake cyclic-steam oil sands operation (Imperial Oil interest, 100 percent) continued with the start-up of an expansion phase that will add 45 thousand barrels per day of heavy oil production. Expansion activities continued at the Syncrude project (Imperial Oil interest, 25 percent), a tar sands mining and crude oil upgrading operation.

In Eastern Canada, the Terra Nova development (ExxonMobil interest, 22 percent) off Newfoundland started up and is producing 150 thousand barrels per day (gross).

Also off Newfoundland, optimization and debottlenecking at the Hibernia field (ExxonMobil interest, 33 percent) have increased gross oil production by about 20 percent to 180 thousand barrels per day.

At the Söhlingen gas field 50 miles from Hamburg, Germany, advanced drilling technologies are used to economically produce "tight gas" reserves, which are difficult to access with conventional methods. This helps prolong field life.



Gas production from the ExxonMobil-operated Sable Offshore Energy Tier 1 development project (ExxonMobil interest, 51 percent; Imperial Oil interest, 9 percent) off Nova Scotia averaged 505 million cubic feet per day (gross). Tier 2 development is under way with start-up scheduled in 2003.

South America

In Venezuela, the ExxonMobil-operated Cerro Negro heavy oil project (ExxonMobil interest, 42 percent) produced more than 100 thousand barrels per day (gross) of extra-heavy crude oil.

In Brazil, two wildcat wells encountered hydrocarbons in the Campos Basin BC-10 block (ExxonMobil interest, 30 percent). Further work is planned to appraise the commerciality of this block.

Europe

ExxonMobil is the largest net producer of hydrocarbons in Europe. Daily net production totaled more than 590 thousand barrels of liquids and nearly 4.5 billion cubic feet of gas, representing 32 percent of ExxonMobil's worldwide production.

In the North Sea, several developments are under way that build on ExxonMobil's high-quality asset base and take advantage of existing infrastructure.

In the Norwegian sector of the North Sea, development continued on the ExxonMobil-operated Ringhorne project (ExxonMobil interest, 100 percent), as the Ringhorne platform started up in early 2003. The 11.4 thousand-ton topside lift set an ExxonMobil and Norwegian Continental Shelf record.

The ExxonMobil-operated Sigyn subsea development project (ExxonMobil interest, 40 percent) began production in December, three months ahead of schedule. Predrilling was completed on the Grane project (ExxonMobil interest, 26 percent), and start-up is anticipated in late 2003.

In the United Kingdom North Sea, the Penguins project (ExxonMobil interest, 50 percent) started production in January 2003. ExxonMobil also participated in the Nessie gas discovery on Block 49/20b (ExxonMobil interest, 29 percent).

In Germany, ExxonMobil Production Deutschland GmbH (ExxonMobil interest, 100 percent) assumed operatorship of the combined production operations of Mobil Erdgas-Erdöl GmbH (ExxonMobil interest, 100 percent) and BEB Erdgas und Erdöl GmbH (ExxonMobil interest, 50 percent), which is expected to lead to significant cost savings.

Offshore the Netherlands, the K/15-FK platform (ExxonMobil interest, 23 percent) was set in October, only 19 months after discovery. Start-up is expected in 2003.

Africa

In West Africa, ExxonMobil has a substantial, profitable production base of nearly 350 thousand barrels per day (net) and significant growth potential. We have a strong, high-quality acreage position with world-class new resource discoveries. A large number of new development projects are under way.

Offshore Angola, deepwater production in the Girassol field on Block 17 (ExxonMobil interest, 20 percent) increased to 200 thousand barrels per day (gross). Drilling and construction activities are proceeding on the ExxonMobil-operated Xikomba project on Angola Block 15 (ExxonMobil interest, 40 percent). Start-up is anticipated by late 2003, utilizing an Early Production System (EPS), significantly reducing the time between discovery and first production. Also on Angola Block 15, ExxonMobil is progressing the Kizomba A, B and C projects.

Kizomba A will develop the Hungo and Chocalho fields, two of the 13 discoveries made to date on the block. The development is expected to recover about 1 billion barrels of oil (gross), with first production in 2004.

The Kizomba B project is expected to produce about 1 billion barrels of oil (gross) from two additional fields, Kissanje and Dikanza. Development planning is under

Rebecca Jones is an operations associate at the Sable project offshore eastern Canada, where ExxonMobil has a leading presence in offshore exploration and production. ExxonMobil Canada assumed operatorship of Sable in early 2002.

Upstream

way for Kizomba C, which will develop the Mondo, Saxi and Batuque fields.

Exploration success continued in deepwater Angola with the Plutao discovery in Block 31 (ExxonMobil interest, 25 percent).

In Equatorial Guinea, ExxonMobil-operated gross production increased to more than 170 thousand barrels per day through optimization of existing infrastructure and continuation of our highly successful drilling program in the Zafiro field (ExxonMobil interest, 71 percent).

The Houston-based Nigerian Reservoir Studies program enables Nigerian geoscientists and engineers to enhance their technological knowledge and skills. Pictured below, foreground, left to right: O. Okonkwo, Andrew Grant, Wendy Burgis (program coordinator) and Otu Udoudo. In background: Nonny Nwogbo and instructor Ken Monson.

Drilling and construction are under way on the Southern Expansion Area project. This project will utilize subsea wells tied to an EPS.

In Nigeria, ExxonMobil produces more than 500 thousand barrels per day (gross) in the shallow waters of the Niger Delta (ExxonMobil interest, 40 percent). The ExxonMobil-operated Yoho development began initial production in late 2002, two years ahead of full-field start-up, using an EPS. Construction and drilling activities are under way on the Bonga field development (ExxonMobil interest, 20 percent), industry's first deepwater development offshore Nigeria. Development activity continues on the ExxonMobil-operated Erha deepwater project (ExxonMobil interest, 56 percent).

Exploration success continued in deepwater Nigeria with five discoveries. ExxonMobil executed a Production Sharing Agreement for operatorship of Oil Prospecting License 214 (ExxonMobil interest, 55 percent).

In Chad, the ExxonMobil-operated onshore Doba project (ExxonMobil interest, 40 percent) is progressing, with early oil production expected from the Miandoum field in 2003, ahead of schedule, followed by full production, including the Kome and Bolobo fields, beginning in 2004. Completion of the Chad-Cameroon pipeline, which will carry oil from the fields in Chad to a terminal in Cameroon, is expected in mid-2003, a year ahead of the original schedule. Six additional fields with 75 million barrels of net oil have been discovered.

The *Falcon* floating, production, storage and offloading vessel (FPSO), shown here under construction in Singapore, will help develop the Yoho field offshore Nigeria, marking the first deployment of an Early Production System.

Asia Pacific

ExxonMobil has large-scale, profitable production operations throughout the Asia Pacific region. In Indonesia, the ExxonMobil-operated Arun and satellite fields (ExxonMobil interest, 100 percent) produced 1.2 billion cubic feet per day of gas (gross) in 2002 and supplied liquefied natural gas (LNG) to Far East markets. The company completed acquisition of a 3-D seismic survey in the onshore Cepu block in east-central Java and analysis is under way.

In Malaysia, ExxonMobil is the largest oil producer, with gross operated production of 276 thousand barrels per day. Significant production increases were achieved through record-high drilling in new projects and existing fields. Net gas sales of 690 million cubic feet per day were an all-time high, due in part to the offshore Angsi development (ExxonMobil interest, 50 percent), which began producing in late 2001. Two new gas developments, Bintang A and B, are scheduled to start up in 2003.

In Australia, gas sales began from the ExxonMobil-operated Gippsland Basin fields to Tasmania, providing the first natural gas to the island state. The offshore Bream Gas Cap development (ExxonMobil interest, 50 percent) came on line six months ahead of schedule, providing additional production from Bass Strait.

A 3,900-square-kilometer 3-D seismic survey, the largest ever acquired in Australia's Bass Strait, was completed, covering the entire northern margin of the Gippsland Basin. A discovery on Australia's Northwest Shelf significantly enlarged the size of gas discoveries made by the Jansz and Io wells drilled in 2000 and 2001.

In Papua New Guinea, plans proceeded to commercialize gas from the onshore Hides area. Agreement was reached with the government on terms and conditions for the project, and conditional gas-sales agreements were signed with potential customers in Australia.

Caspian Region

In the Caspian, ExxonMobil is in the unique position of participating in the development of three of the largest fields in the world.

In Kazakhstan, ExxonMobil increased its equity in the North Caspian Production Sharing Agreement, which includes the giant Kashagan field and additional exploration acreage, bringing the company's total share to about 17 percent.

Appraisal and development-planning activities are progressing toward first production from Kashagan. One appraisal well was completed and two additional wells are under way. A 3-D seismic acquisition program was completed to aid in development planning. Several phases of expansion will be required to fully develop this world-class discovery — the largest gross resource that ExxonMobil has participated in developing in more than 30 years.

Exploration drilling encountered hydrocarbons in the North Caspian Kalamkas wildcat well. Results are under evaluation.

Recent projects have increased production capacity from Kazakhstan's Tengiz field (ExxonMobil interest, 25 percent) to 300 thousand barrels per day (gross). The Caspian Pipeline Consortium (CPC) pipeline (ExxonMobil interest, 7.5 percent) was completed, and Tengiz production is being exported through the CPC.

In Azerbaijan, gross production from the Megastructure (ExxonMobil interest, 8 percent) totaled 130 thousand barrels per day. The Phase 1 expansion is under way in the Central Azeri field.

Russia

ExxonMobil is operator of the Sakhalin I project (ExxonMobil interest, 30 percent) which, when completed, will represent the largest greenfield foreign investment in Russia. Construction and drilling activities for the initial phase, expected to develop 1.5 billion oil-

Upstream

equivalent barrels (gross), are under way. Additional exploration on acreage awarded under the Sakhalin III tender awaits the passage of enabling Russian legislation.

Middle East

ExxonMobil has a substantial production base and significant growth potential in this resource-rich region.

In Qatar, ExxonMobil is working with its partners to expand the successful Qatargas and RasGas ventures (ExxonMobil interest, 10 percent and 25 percent, respectively). Construction is under way for RasGas LNG trains 3 and 4. These world-scale trains will have a combined capacity of more than 9 million metric tons annually (MTA), with first LNG deliveries scheduled for 2004 and 2005, respectively.

The Al Khaleej Gas Development Production Sharing Agreement (ExxonMobil interest, 100 percent) will further develop gas resources from Qatar's North Field for domestic and regional pipeline sales. Agreements to supply gas to domestic buyers are progressing. Key commercial terms have been agreed upon with Kuwait Petroleum Corporation for long-term sales of natural gas. A Memorandum of Understanding was signed with Bahrain for additional pipeline sales.

We have completed a commercial and technical feasibility study for a gas-to-liquids project in Qatar and discussions are ongoing with Qatar Petroleum.

In Yemen and Abu Dhabi, ExxonMobil has onshore oil operations with net production totaling more than 110 thousand barrels per day.

In Saudi Arabia, ExxonMobil is the lead company and operator for two of three core ventures designated to implement the Kingdom's strategic gas initiatives. Negotiations continue on these projects.

Gas and Power Marketing

ExxonMobil is the world's largest non-government producer and marketer of equity gas. During 2002, equity gas sales exceeded 10 billion cubic feet per day, with total sales of 19 billion cubic feet per day. Proved reserves total 56 trillion cubic feet and discovered resources total 185 trillion cubic feet.

ExxonMobil is focused on marketing equity natural gas and natural gas liquids to established customers. This approach has been successful through changing market conditions. With operations on five continents and in more than 25 countries, ExxonMobil participates in every major gas market in the world. The company manages almost 1 million barrels per day of natural gas liquids and has significant holdings in the electric power business, with interests in nearly 13,000 megawatts (MW) of generation capacity, including cogeneration.

In North America, the company markets its significant natural gas and natural gas liquids production and also focuses on introducing gas to U.S. markets from new developments, including Thunder Horse in the deepwater Gulf of Mexico and the large resources in the Mackenzie Delta region of Canada.

The European Union's (EU) gas market directives are increasing opportunities for direct gas sales to European customers. ExxonMobil is well-positioned as the largest nongovernment marketer of equity gas in Europe and is taking steps to build on these strengths as the market evolves.

ExxonMobil conducts a program to prepare students to operate the Sakhalin I oil and gas facilities in Russia. Training begins with instruction in English. Students of this English class in Yuzhno are, left to right: Vitaly Gribanov, Semyon Kaplin, Ramil Denislamov, Evgeny Dregalov, Vladimir Alekseev, Vyacheslav Klimachev, Sergei Podorvanov, Vladimir Romashov, Aleksei Kalekov and Dmitry Shinkarev. Seated at the desk is the instructor, Nadezhda Rolya.

Left to right: Mohd Salimi Saidin, Ho Chooi Yee, Norsiah Adnan and Ed Mayhall discuss plans to expand existing developments off Malaysia with satellite platforms. ExxonMobil is the largest oil producer in Malaysia.

Because of the evolving gas market in Europe, the marketing of Norwegian gas was restructured to include the unitization of Norwegian offshore pipelines and direct selling of ExxonMobil gas across Europe. As part of the unitization, ExxonMobil's ownership rights in these assets were extended to 2028.

In April 2002, preliminary agreement was reached with the government of the Netherlands to restructure the Netherlands gas venture. This agreement would facilitate ExxonMobil's ability to independently sell our share of the gas directly to customers.

In mid-2002, ExxonMobil agreed to the transfer of shares in the German gas-marketing company, Ruhrgas, to E.ON. Completion of this agreement requires several conditions to be met.

In Asia Pacific, ExxonMobil is the major supplier of gas to Peninsular Malaysia, meeting the growing demand for power generation. Gas deliveries under the Gas Production Sharing Contract, signed in 1997, began in 2002 and will continue for 25 years.

The company is the largest supplier of gas to the growing Eastern Australia market. Key terms have been agreed upon with major customers for additional sales from Gippsland.

We have initiated discussions with potential customers in Japan for pipeline gas from Russia's Sakhalin Island. We signed a joint-venture framework agreement and continue to participate in developing definitive agreements that will allow full evaluation of the China West-East Pipeline project.

Power

In 2002, the power segment of our business was combined with Gas Marketing to take advantage of synergies in the businesses. Also, a Power and Gas Services (PGS) organization was established to take advantage of opportunities in the increasingly linked gas and power markets and to capture synergies between the company's power- and gas-marketing activities. PGS works with our operating sites to maximize the value of ExxonMobil's cogeneration operations, minimize the cost of purchasing power and gas for ExxonMobil's facilities, and pursue new power projects that capture synergies with existing ExxonMobil operations.

In Hong Kong, Castle Peak Power Company (ExxonMobil interest, 60 percent) owns almost 6,300 MW of electricity generation capacity, and we have a 51 percent interest in an additional 600 MW. Power demand in Hong Kong and neighboring Guangdong province in China is growing. At the Black Point Power Station, an expansion project is under way to install the final two of eight planned high-efficiency gas turbine units, each with more than 300 MW capacity.

LNG

ExxonMobil is a global leader in developing and marketing liquefied natural gas (LNG). In 2002, the company participated in joint ventures in LNG plants with a combined gross capacity of 20 MTA, nearly 20 percent of global industry capacity, making us one of the largest nongovernment LNG suppliers in the world.

With our co-venture partners, we continue our long-standing role as a major LNG supplier to the large markets in Japan and Korea. Looking to the future, we are marketing new LNG supplies to India and continuing to finalize agreements for sales into southern Europe.

Pursuing new opportunities in Europe, ExxonMobil signed a Heads of Agreement with Qatar to supply LNG to the United Kingdom and continental Europe. The agreement calls for the development of two LNG trains that are expected to be the largest ever built. We also continue to evaluate LNG opportunities in Nigeria, Angola and offshore Western Australia.

With the breadth of ExxonMobil's resources, our experience in commercializing advanced technologies, and a long, successful history of working with customers around the world, we are well positioned to supply additional LNG to growing markets in the Far East, Europe and the United States.

An LNG tanker takes on a shipment at the Ras Laffan loading jetty in Qatar. ExxonMobil is a leader in the world's LNG market.

Downstream

Strong operating performance in a challenging margin environment	
Earnings	$1.3 billion
Return on average capital employed	5.0 percent
Capital expenditures	$2.4 billion
Petroleum product sales (barrels/day)	7.8 million
Refinery throughput (barrels/day)	5.5 million

ExxonMobil's downstream organization acquires and processes crude oil and other petroleum feedstocks into high-quality products that are marketed to consumers and industry. The global functional structure of ExxonMobil distinguishes the company from the competition and enables us to fully leverage the world scale of our operations as we relentlessly drive to be the most effective competitor in every market served. The downstream business comprises four global functional companies: Refining & Supply, Fuels Marketing, Lubricants & Specialties, and Research & Engineering.

2002 Results

Discipline, commitment and an unwavering focus on excellence are important in the best and the most challenging of times. In 2002, this approach delivered operating cost efficiency and revenue enhancements that contributed to $1.3 billion of downstream earnings. These efforts helped partially offset very low refining and marketing margins, as crude costs rose faster than product prices in an environment of depressed industry demand growth. These conditions, in our intensely competitive industry, reduced earnings by 70 percent from the previous year.

Refining & Supply

ExxonMobil is the world's largest refiner, with an ownership interest in 46 refineries in 26 countries and a total capacity of 6.3 million barrels per day. It has an extensive transportation network of oil tankers, pipelines and product terminals. Lubes-refining capacity is 150 thousand barrels per day.

In 2002, the refining industry experienced some of the lowest margins in more than a decade. Despite the adverse market conditions, the global Refining & Supply organization continued to leverage its scale with the worldwide implementation of proprietary management systems. These systems are designed to improve the performance of all operations to pacesetter levels and cover all aspects of our business. They place particular focus on safety and environmental performance and on the identification and

ExxonMobil's downstream businesses span the globe.

ExxonMobil Presence

implementation of initiatives for cost reduction, margin enhancement and reductions in capital requirements. Examples include ExxonMobil's Global Energy Management System, which is reducing the energy consumed by refinery operations. Another is the Global Reliability and Maintenance Management System, which increases equipment reliability and availability while reducing maintenance costs. These and other initiatives have contributed to a 5 percent annual productivity improvement over the past several years. Refining & Supply maintained its focus on delivering the highest level of safety and operating performance, with continued emphasis on the Operations Integrity Management System. An enhanced Product Quality Management System, which ensures that products continuously meet high quality standards, was also introduced.

Strategies

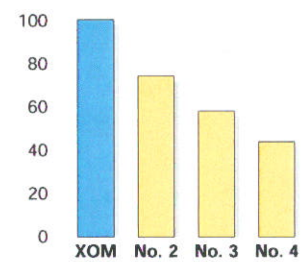
- Deliver best-in-class cost and operating performance
- Capitalize on refining integration with chemicals and specialties businesses
- Be the company brands of choice
- Increase sales of high-value fuels, lubricants and specialty products
- Maximize total retail outlet site earnings
- Optimize portfolio and invest selectively
- Rapidly develop and deploy leading-edge technology

ExxonMobil's disciplined approach to capital investment continues to be a competitive advantage. Our capital project management system has delivered annual improvements of 3 percent in project cost performance and is externally benchmarked in the top tier of the refining industry. This proven system will be especially important as we invest in our refineries to meet more-stringent motor fuel quality

Earnings and Return on Capital Employed

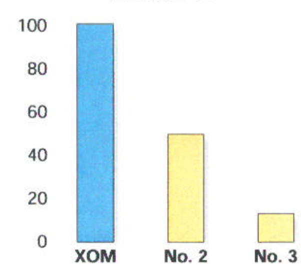
Leadership in Refining Capacity

ExxonMobil Compared With Leading Competitors
ExxonMobil = 100



Leadership in Lube Basestocks

ExxonMobil Compared With Leading Competitors
ExxonMobil = 100



Downstream

specifications around the world. The application of ExxonMobil's *SCANfining* process, which uses proprietary catalysts to remove sulfur with minimal octane loss, at a lower cost than other commercially available technologies, has helped reduce the investment required to meet these specifications. Our success in selling licenses to a number of third-party refinery operators clearly demonstrates that others in the industry have also recognized the value of this technology.

Several new ExxonMobil-developed technologies were applied in 2002, including advances in molecular-focused manufacturing processes to further improve product quality and yield higher-value products at lower cost. In addition, a new computer model was applied to improve operations of ExxonMobil's fluid catalytic crackers.

Commercial negotiations and project-development activities continued on two potential major integrated refining, petrochemical and fuels marketing joint ventures in south China.

Liquefied petroleum gas (LPG) is delivered to the Torrance, California, refinery by rail. Operators Jennifer Heisinger and Brian Evans check the pressure in the hoses used for offloading a shipment of LPG from a railcar.

On the Run retail stores and the *Speedpass* program offer customers convenience and speed in shopping and refueling. ExxonMobil employee Shirley Johnson uses her *Speedpass* transponder to gas up at a store in Houston.

Applying Technology

Molecular-Focused Manufacturing

ExxonMobil is taking plant optimization to a higher level by combining a number of proprietary processes and technologies across the supply and manufacturing chain to develop a molecular-based approach that is unique to ExxonMobil. The ability to fingerprint crudes, feedstocks and products, combined with advanced modeling of manufacturing operations at a molecular level, improves our decision-making capabilities. It also provides a significant competitive advantage by delivering higher-value products at lower cost.

Fuels Marketing

Worldwide, ExxonMobil markets gasoline and other fuels at more than 40 thousand service stations, serves more than 1 million industrial and wholesale customers, provides aviation services and products at more than 700 airports, and services ocean-going vessels in more than 300 ports.

Although earnings were adversely affected by weak industry margins, underlying business performance improved.

To maximize total retail site earnings and to support success under these challenging conditions, Fuels Marketing focuses on four key areas: cost reductions, nonpetroleum income growth, selective and disciplined new investments, and high-grading service stations. A portfolio of market-specific retail formats has been developed using a rigorous process that involves assessing customer preferences and market testing. Local market considerations determine the format selection, which is then consistently and efficiently applied.

One example of this approach is the popular *On the Run* convenience store format. In 2002, Fuels Marketing expanded this format in existing markets and in several new ones, with 180 new stores added, bringing the total to more than 800 in 28 countries. Combining the strength of ExxonMobil-branded fuels with leading food suppliers has also proven to be a winning format to increase site performance. We already have a successful alliance with food retailer Tesco in the United Kingdom. In 2002, further alliances were piloted with new partners in Europe and Africa.

Customer convenience is being further enhanced through a number of unique offerings. We have continued the expansion of our unmanned *Esso Express* format, with

Downstream

The multinational team at the European Customer Service Center in Manchester, England, takes care of 20,000 customers across the continent. Pictured here are, front row, left to right: Nadim Mogul, Nicole Maxted, Alison Brown and Matthew Vrancken. Back row: Carlos Canales, Sophie O'Hara, Hannu Kovero, Frode Eriksen, Heidi Robson, Malin Greenan and Salvo Teriapopolo.

sites throughout France and in Belgium.

The innovative *Speedpass* program is now used by more than 6 million customers in the United States, Canada and Singapore for quick, convenient payments at our retail sites. Watch manufacturer Timex has introduced a limited quantity of *Speedpass*-enabled watches, an exciting next step in the customer-friendly evolution of the program.

ExxonMobil has also implemented several programs to recognize and reward loyal customers. For example, in the United States, through the Upromise program, ExxonMobil contributes a portion of each enrolled customer's fuel purchase to a college savings account. The *Smiles* driver rewards program, launched in Singapore, Malaysia and Hong Kong, rewards customers with points that can be used for purchases or transferred to proprietary airline and credit card loyalty programs.

Fuels Marketing also continues to pursue efficiencies by leveraging its global scale. Operating expenses were further reduced through initiatives such as the consolidated European Customer Service Center in Manchester, England. The center employs 350 multilingual customer-service advisors who speak 10 languages and serve 20,000 customers throughout Europe. On a typical day, 3,000 customer orders are processed and 700 trucks are dispatched. More than 1 million invoices are generated each year.

By concentrating on developing and applying market-focused offerings and the continued delivery of operational efficiencies, ExxonMobil Fuels Marketing is taking the necessary actions to compete successfully in a dynamic marketplace.

Lubricants & Specialties

ExxonMobil is the world's number-one supplier of lube basestocks and a leading global marketer of finished lubricants and specialty products. *Exxon*, *Esso* and *Mobil* lubricants provide solutions for automotive, commercial, industrial, marine and aviation customers around the world.

The technology investments, supply-chain improvements and marketing initiatives completed in 2002 contributed to improved earnings and will support tomorrow's growth.

As demand for higher-quality lubricants grows, so does the need for higher-performance basestocks. ExxonMobil's proprietary zeolite catalysts provide a notable opportunity in this area. Using these catalysts in a wax isomerization unit in Fawley, United Kingdom, will yield a new product with substantially enhanced performance characteristics compared with other commercially available premium basestocks.

Supply-chain improvements continued. Product lines were streamlined, blend plants were consolidated, and use of a cost-saving process for grease manufacturing was expanded. Implementation of sophisticated planning-and-scheduling technology, which optimizes supply and distribution networks, progressed across the globe. These efforts will continue in 2003.

Our marketing strategy supports alignment of the *Exxon*, *Esso* and *Mobil* offerings with the needs of customer segments. Each brand is supported by distinct and consistent communications. Our global marketing program has been developed to enable ExxonMobil to capture efficiencies while maintaining flexibility to adapt to local market conditions.

The world's leading synthetic motor oil, *Mobil 1*, was reformulated with the *SuperSyn* anti-wear technology system. Achieving double-digit sales growth in the United States, this enhanced product added new factory-fill and service recommendations from Cadillac XLR, Porsche Cayenne and Mitsubishi's Lancer Evolution in North America to an already impressive list from worldwide original equipment manufacturers.

To meet strict new engine-emission requirements in North America, ExxonMobil reformulated and improved the performance of its commercial engine oil brands, *Delvac* and *XD-3*. This sets the stage for development of a common product platform for the rest of the world. With heavy-duty truck fleets accounting for nearly two-thirds of diesel engine oil demand, ExxonMobil is working with distributors in key markets to target profitable segments in this sector.

Motorsports sponsorships, such as those with Penske Racing and West McLaren Mercedes, continue to lead to new business and provide an ideal environment for developing high-performance lubricants. Sponsorship of Toyota's new *Formula 1* team helps bolster ExxonMobil's position as a primary supplier of lubricants for Toyota factory and service fill.

Beginning in 2003, *Mobil*-branded products were named "Official Lubricants of NASCAR." This tie-in with one of America's fastest-growing sporting events provides a level of exposure benefiting sales across the *Mobil* brand family.

ExxonMobil's worldwide service capability and focus on strategic global accounts differentiate it from the competition in the lubricants business. In 2002, CEMEX, a leading global producer and marketer of cement and ready-mix products, selected ExxonMobil as its worldwide sole-source supplier of lubricants and in-plant lubrication services. Elsewhere, product leadership and superior customer service helped grow ExxonMobil's global marine lubricants business and gain important new customers such as Marcas and United Arab Shipping.

Strong brands, high-quality products and expanded use of distributors are boosting sales in emerging markets. In Eastern Europe and China, for example, we achieved double-digit volume growth. In China, ExxonMobil won significant new business at the Three Gorges Dam, the world's largest hydroelectric project.

Outstanding global brands, proprietary technology and a low-cost, efficient supply chain help make up the platform for continued success.

ExxonMobil's Len Brammeier, left, conducts a lubrication survey with Ernesto de la Cruz at the new CEMEX Balcones plant in New Braunfels, Texas.

Chemical

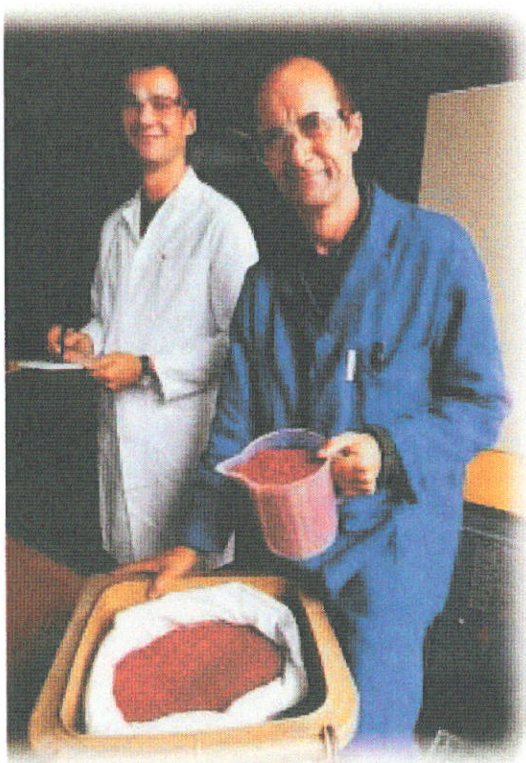
Focused on fundamentals	
Earnings	$0.8 billion
Return on average capital employed	6.1 percent
Capital expenditures	$1.0 billion
Prime product sales (metric tons)	26.9 million

2002 Results

ExxonMobil's chemical business maintained a focus on capital discipline and cost reduction to achieve industry-leading returns of 6.1 percent despite the most challenging industry environment in two decades.

This focus has allowed the company to invest in profitable growth, nearly tripling capital employed over 20 years while improving returns across business cycles. Returns have increased during the peaks as well as the troughs of the industry cycle.

Our investments in recent capacity additions in Saudi Arabia and Singapore resulted in the fourth consecutive year of record prime product sales volumes — 26.9 million metric tons — 4 percent above last year's level. Excluding special items of $175 million recorded in 2001, chemical earnings of $830 million for 2002 were $123 million higher than last year, as record sales volumes offset lower margins.



Sebastien Dessenne and Joel Batel test color to meet customer requirements at the ExxonMobil Chemical SAS polypropylene plant at Lillebonne, France. The plant serves the European automotive and household appliance markets.

The recent capacity additions in Saudi Arabia and Singapore also allowed us to increase our participation in high-growth markets such as China. In addition, commercial negotiations and project-development activities continued for two world-scale integrated refining, petrochemical and fuels marketing joint ventures in southern China that could further enhance our competitive position in this important market.

A key contributor to our performance is an exceptional mix of businesses. Our cyclical olefin, polyolefin and aromatics businesses have an advantage over those of the competition because of feedstock flexibility, unmatched integration with our other petroleum businesses, and exceptional technology. ExxonMobil also has a strong position in a broad range of specialty chemical businesses that provide attractive returns throughout the industry cycle.

Customer-focused

As a leading global polyethylene supplier, we are helping our customers in markets such as films to be more cost-effective. For example, our state-of-the-art *Exceed* resins are used to make agricultural greenhouse films that are thinner and longer-lasting, provide improved optical clarity, stay cleaner and resist punctures better than conventional films.

Since 1999, we have nearly doubled our capacity to produce polypropylene, a plastic with some of the fastest-growing uses, to 2.2 million tons per year by using new, world-class-volume production lines and acquiring additional capacity.

New polypropylene resins developed for the films industry, using the latest catalyst technology, have found broad acceptance. We have developed a premium grade for the nonwoven textile industry that is now a standard for fine-fiber production for diaper components, hygiene products, filters and many other nonwoven applications.

In addition, ExxonMobil has developed a new polypropylene product for automotive bumpers that provides excellent appearance, resists scratches and can be used in both mold-in color and partial-paint applications.

Investment in specialties

ExxonMobil offers one of the broadest portfolios of synthetic rubber products on the market. At Baytown, Texas, production capacity of halobutyl rubber more than doubled through plant modifications. The project also helped reduce emissions. This expansion was driven by continuing growth of halobutyl in the tire market worldwide and by significant growth in the Asian pharmaceutical market for bottle and container stoppers, where higher quality requirements are driving conversion from natural rubber to synthetic rubber.

Over the past decade, the company doubled its capacity of *Escorez* tackifying resins and extended its geographic coverage with a plant in Jinsen, China, to better serve the increasing and global needs of our customers in the adhesion industry. During that time, we also commercialized new products for adhesive applications and, most recently, for novel products that improve the properties of commodity polymers.

The company became the sole owner of Advanced Elastomer Systems, known worldwide for *Santoprene* engineered thermoplastic elastomers. These unique products offer customers design options, reduced costs and improved performance for applications in a wide variety of markets. Like plastics, they can be extruded, molded or thermoformed easily and economically into an almost limitless variety of shapes. Like rubber, they are resilient, flexible and resistant to heat, fluids and chemicals.

Our extraordinarily thin and flexible oriented polypropylene films solve packaging and labeling problems, reduce production costs and create appealing package designs that help consumer-product companies promote their products. Ultra-high-barrier oriented polypropylene films are replacing aluminum in the packaging of food products such as dry mixes.

The year saw the introduction of a film to replace metallized paper in water-based, glue-labeling applications. The film is the

The strength of ExxonMobil Chemical's *Exceed* polyethylene is demonstrated at China's largest plastics trade show.

first of its kind to run on most existing paper-labeling equipment without machinery or adhesive modifications. In response to demand growth, capacity was expanded at the Brindisi, Italy, plant. New production is being added at facilities in Belgium and the United States.

Stimulating progress

The widespread sharing and rapid implementation of "best practices" across an extensive chemical-manufacturing base enable us to increase capacity with little or no added cost at many of our facilities. The North American polyethylene business increased capacity by 5 percent without additional investments. Facilities in Singapore and China increased capacity as well.

In Baytown, Texas, a new ethylene steam-cracking furnace at the olefins plant incorporates the latest technology to minimize emissions, noise and energy use. It is the largest of its kind at any ExxonMobil site, with 40 percent more throughput than other designs. The Meerhout polymers plant in Belgium, one of Europe's largest low-density polyethylene manufacturers, expanded annual capacity by 10 percent.

More than 90 percent of the chemical company's owned and operated facilities are integrated with refining or gas-processing operations. On-site teams in all operating regions are working to achieve energy-saving opportunities that will reach about 15 percent of total energy use in the coming years. To capture synergies from combined utility demand, cogenerated electric power and heat are expected to increase by more than 40 percent over the next four years.

Energy-efficiency improvements at the Mont Belvieu, Texas, plastics plant, the Edison, New Jersey, synthetics plant and throughout ExxonMobil Chemical Company earned Energy Efficiency Awards from the American Chemistry Council.

Our technology advantage

New technologies help us get the most from our asset base, invest efficiently for future growth, maximize the value of our product mix and develop new products.

Our chemical technology program has resulted in several licensing agreements.

Univation Technologies, a licensing joint venture, is developing breakthrough catalysts to make bimodal high-density polyethylene in a single reactor. This is significantly more cost-effective than traditional two-reactor technologies.

The company's *XyMax* and *PxMax* processes for manufacturing aromatics are available through Axens, a major process licensor to the petrochemical, refining and natural gas industries.

New plants in Saudi Arabia and Thailand and new steam-cracking furnaces in Texas and China will operate with *Selective*

Strategies

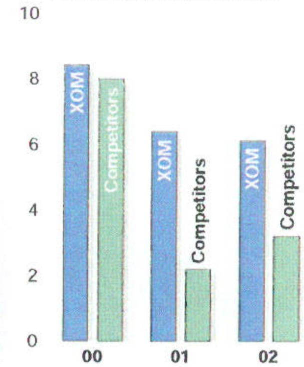
- Continuously reduce costs to achieve best-in-class performance
- Capture full benefits of integration across all ExxonMobil operations
- Focus on businesses that capitalize on core competencies
- Build proprietary technology positions
- Invest selectively in internationally advantaged projects

Chemical

Employees such as Claudio Cardoso at the Paulinia, Brazil, fluids plant excel in emergency preparedness.

Continuing to Outpace the Competition

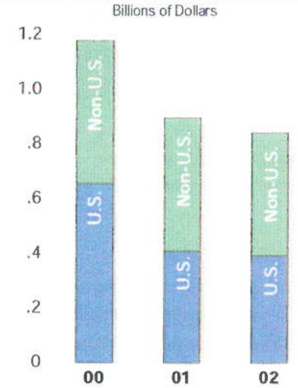
Percent Return on Capital Employed



ExxonMobil vs. average of major petrochemical competitors

Regional Earnings

Billions of Dollars



Cracking and Optimum Recovery (SCORE), a licensed process that combines ExxonMobil's and Halliburton KBR's steam-cracking technology.

The technology heritage of our polymers businesses was commemorated at the 20th anniversary of the Baytown Polymers Center, where a number of breakthrough inventions in metallocene technology ushered in a new era of precision plastics. Our understanding of polymer-structured property relationships allows us to make new products using some of the most advanced equipment and techniques in the world.

Technology helps us get more out of our current facilities and invest efficiently for future growth. We constantly reassess our product portfolio to maximize the value of our product mix and to develop products for new applications as plastics continue to displace other materials.

At an ExxonMobil Chemical research laboratory in Baytown, Texas, Alistair Westwood uses a scanning electron microscope to investigate the chemistry of catalysts, polymers and end-use products.

Major coal and copper operations divested

Earnings from discontinued operations	$0.4 billion

In 2002, ExxonMobil continued to apply a disciplined approach to asset management with the divestments of its coal operations in Colombia and its copper operations in Chile. ExxonMobil had invested in these assets, operated them profitably and sold them at a profit. These sales were consistent with the company's asset-management program, which seeks to achieve maximum value from each operation.

Coal

Early in the year, ExxonMobil sold its 50-percent interest in the Cerrejon Mine in Colombia to its joint-venture partners. Operations at the mine began in 1984. Cerrejon eventually became the world's largest export coal mine, with shipments to utility and other customers worldwide. Infrastructure investments in recent years, including the development of adjacent new mining areas, enabled the mine to achieve record annual volume of more than 19 million tons in the last full year of ExxonMobil operation. Operational improvements were also achieved through selected use of technology, such as global positioning for trucks and other mobile equipment, as well as equipment upgrades.

ExxonMobil owns and operates the Monterey No. 1 Coal Mine in Illinois. Monterey's low-sulfur reserves are attractive to electric utility companies in the area. Record production from the mine in 2002 totaled 3 million tons.

Communications Technician Alan Breiner (seated) and Surface Supervisor Bob Whitmore monitor coal conveyance and production rates at ExxonMobil's underground Monterey No. 1 Coal Mine in Carlinville, Illinois. Coal is fed onto the conveyor system at speeds ranging from 1,100 to 1,600 tons per hour.

Minerals

ExxonMobil sold its interest in copper operations in Chile in the fourth quarter of 2002. The operations, which included two copper mines and a smelter, were acquired in 1978 from the Chilean government. Selected investments to increase mining and smelting capacity more than doubled copper production in the 1990s to a record 254 thousand metric tons of copper in 2000, making the operation a world-class copper producer. Higher productivity and lower unit costs were also achieved through process improvements, mine planning and increased equipment reliability.

Prior to the sale, two projects at the Los Bronces Mine were completed to further increase throughput and copper recovery. The projects were designed to add 60,000 metric tons of fine copper production annually.

Production of fine copper during 2002 was unchanged from prior years. Earnings reflected copper prices that were slightly lower than those in 2001.

Business changes

With the sale of its Colombian coal and Chilean copper operations, ExxonMobil exited the coal and minerals businesses outside the United States. Responsibility for U.S. coal was assumed by the upstream business function.

Corporate Responsibility

Maintaining public trust

Every day, ExxonMobil serves the energy needs of millions of people around the globe. We succeed in this important role by maintaining public trust. To keep this trust, which has been developed during our 120 years of doing business, we strive to be a leader in corporate responsibility by operating with integrity, maintaining a steadfast commitment to health, safety and environmental protection, playing a positive role in the global community, and setting and meeting the highest ethical standards in the way we conduct our business.

Corporate governance

ExxonMobil has a long-standing tradition of leadership in corporate governance. We are committed to the concept of integrity in accounting and sound business and financial controls. We have demonstrated this commitment by our long history of independent outside directors and key board committees with oversight responsibility for the company's financial controls and practices.

"Nobody Gets Hurt"

ExxonMobil believes that the first priority in running our business is safety. We believe that when an organization is committed to safety and has accomplished its safety goals, it maintains the same commitment and discipline in every other aspect of the business. In other words, safety is the foundation for the sound, prudent and efficient conduct of our operations.

Our safety motto is "Nobody Gets Hurt." We are proud of the fact that 2002 was the safest year in ExxonMobil's history and that we led the industry.

We are committed to the safety of everyone involved in or affected by our operations. This includes employees, contract partners in the workplace, people in communities near our facilities and customers.

Our Operations Integrity Management System (OIMS) provides a framework for controlling the safety and environmental risks inherent in our business. It is designed to help drive all operational incidents to as close to zero as possible.

Esso Norge AS employees (from left) Mike Cousins, Ingvild Skare, Solve Waalen and Geir Indrebo review an environmental business plan that incorporates environmental protection into day-to-day business decisions at the Ringhorne platform offshore Norway.

The least tern is one of four protected bird species that inhabit a built-up island in the Houston Ship Channel. The island was originally used as a staging area for relocating pipelines. But working with wildlife agencies, ExxonMobil made modifications to turn it into a bird sanctuary.

The people of ExxonMobil have the skills, systems and determination to eliminate work-related injuries and illnesses. We believe we can make further improvements in our safety performance to maintain our position among the safest employers in the world's energy and petrochemical industries.

Environmental performance

Since our adoption of OIMS some 10 years ago, the system has matured into a valuable tool for the prevention of environmental incidents. OIMS also fulfills the environmental management guidelines set by the International Standards Organization.

In 2002, auditors from Lloyd's Register of Quality Assurance reviewed ExxonMobil's environmental management practices and found employees "committed to improvement in environmental performance and improvement of OIMS." It noted that this commitment is evident throughout the organization.

Consistent with safe operating practices and sound economics, ExxonMobil is working to reduce greenhouse-gas emissions in its own operations. We're reducing gas flaring and other energy losses through careful monitoring, maintenance, improved equipment reliability and smarter control technology.

In addition, ExxonMobil uses a disciplined process called Environmental Business Planning to help incorporate environmental protection into local business decisions around the world. For example, our Esso Norway affiliate developed an annual plan that addresses business and environmental issues specific to Norway. The plan makes the best use of resources for safeguarding the environment.

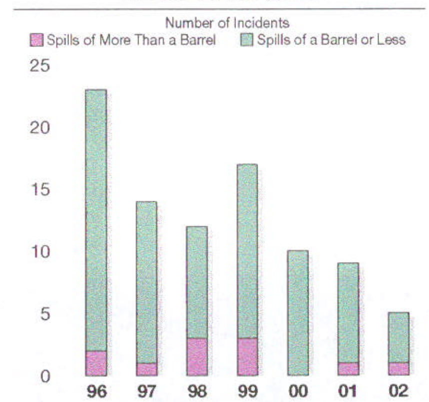
Performance recognition

Our commitment to sound operations has won us significant recognition.

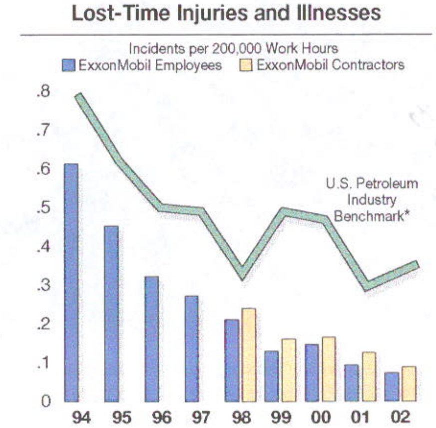
Esso Exploration and Production Chad, Inc., was runner-up for the U.S. Secretary of State's Award for Corporate Excellence for its "outstanding work" in dealing with host governments and indigenous populations in the course of developing oil projects in Chad.

The Baytown, Texas, refinery received the Construction Industry Safety Excellence Award from the Construction Users Roundtable. The award was granted for the creation of "world-class contractor site safety programs and dedication to promoting injury-free construction."

Marine Vessel Spills



Lost-Time Injuries and Illnesses



*Employee safety data from participating API companies

Corporate Responsibility

ExxonMobil Chemical earned the American Chemistry Council's highest level of recognition, the Responsible Care Leadership Award, for excellence in employee safety and health and in safety and environmental management practices.

Marine operations

Our commitment to environmental protection extends to our operations at sea.

At year-end 2002, ExxonMobil affiliate International Marine Transportation Limited had operated 29 months without a single recordable spill. This was achieved while making 2,500 port calls and transporting 800 million barrels of crude oil, petroleum products and chemicals.

We use science and technology to develop practical and cost-effective measures to prevent spills and to be prepared to respond quickly if they happen.

For example, ExxonMobil Research and Engineering Company participated in a joint ExxonMobil/U.S. Minerals Management Service study that demonstrated that crude oil can be chemically dispersed at cold temperatures, thus reducing the impact on the environment. Though we strive for no spills, application of this technology will strengthen the remediation capability of the entire petroleum industry, if needed, for oil exploration and production projects in cold-water areas such as offshore Sakhalin Island in the Russian Pacific.

Instructor Shirley Thompson (center) leads Washington Mitema and Louise Richardson through an exercise to determine the rate of change in the depth of a liquid. It's part of the Crossroads in Mathematics program funded by the ExxonMobil Foundation to improve the teaching of introductory mathematics.

Building better communities

When ExxonMobil begins work in a country, we seek to improve the quality of life in the places our employees call home. We believe this is a fundamental element of good corporate responsibility.

As a science- and knowledge-based company, ExxonMobil supports education programs in most of the communities where it operates. Much of this support comes from the ExxonMobil Foundation through our U.S.-based Matching Gifts program for colleges and universities. We also support projects to strengthen the effectiveness of mathematics teaching and enhance training for science teachers in U.S. elementary schools. Other education support includes providing schools with computers, Internet connections and teacher training in places as diverse as rural Malaysia, Brazil and Sakhalin Island in Russia.

Nurse Heidi Retes (left) tends to a young burn victim at the Conaniquem Rehabilitation Center in Santiago, Chile. Children from throughout South America receive free treatment for burn injuries at the center, founded by Esso Chile and a group of doctors in 1979.

At the National Institute of Medical Research in Lagos, Nigeria, researchers Chimere O. Agomo and Veronica N. Asianya prepare prepackaged doses of antimalaria drugs as part of the Roll Back Malaria program.

In Azerbaijan, we have helped translate and distribute textbooks, dictionaries and encyclopedias. In the United Kingdom, the ExxonMobil Growing School Links Program helps schools with a variety of science, math and environmental education initiatives.

Some nations where we do business are extremely poor and lack infrastructure. As we pursue our work, we often contribute to building local capabilities and improving the local economy. As part of this effort, we emphasize the hiring and training of local employees and contractors, who also benefit from the transfer of skills and technology.

Because we operate in so many developing countries where health care is not readily available, we provide health services to our employees and their families. We often make significant contributions to community health needs, including projects to improve basic water, electricity and sanitation services.

Along these lines, we have joined with others to be strong advocates for strategic health-management programs. Some of these initiatives involve improving health infrastructure, and others are directed at reducing the prevalence of diseases such as malaria.

For example, we are working with host governments and Roll Back Malaria campaigns in five countries in sub-Saharan Africa to combat the spread of malaria. We're also supporting accelerated development of antimalaria drugs and vaccines through the Harvard Malaria Initiative and the Medicines for Malaria Venture.

To help reduce the spread of AIDS in Africa, the company is working with communities and others to strengthen HIV education and prevention programs. This effort includes a public-private partnership in Angola as well as programs in Chad and Cameroon.

In 2002, ExxonMobil and its affiliates contributed $98 million in traditional contributions to nonprofit charitable organizations and in direct investments in community-serving projects. These investments built or upgraded medical facilities, schools, roads, water lines and sewer systems. They also provided scholarships, textbooks, university grants, funding for the arts, disaster relief and other benefits.

One of the largest recipients of company, employee and retiree contributions in the United States continues to be the United Way. Some $16.3 million went to United Way agencies in more than 80 communities in 2002.

Beyond the company's investments, employees, retirees and their families contributed their own time and money to nonprofit organizations. Much of this occurred as part of ExxonMobil's Volunteer Involvement Program, in which individuals donated more than 540,000 hours of their time.

For more information, see ExxonMobil's *Corporate Citizenship Report*, available on our Web site at exxonmobil.com or the "Actions and Results" page on the same site.

Financial Summary

Inside

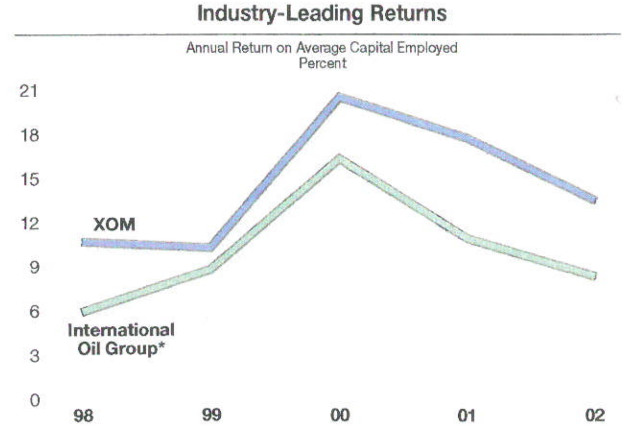
Financial Highlights	29
Shareholder Information	30
Report of Independent Accountants	31
Summary of Accounting Policies and Practices	31
Summary Financial Statements	
Statement of Income	32
Balance Sheet	33
Statement of Cash Flows	34
Volumes Summary	35
Reserves Summary	36
Exploration Success	36
Directors, Officers and Affiliated Companies	37, 38
Investor Information	39

ExxonMobil is managed to enhance long-term shareholder value. Through the execution of long-standing, fundamental strategies that capitalize on our core strengths, the company achieves superior financial and operating results. We believe that ExxonMobil's 2002 results reflect our commitment to being the world's premier petroleum and petrochemical company.

Included in this Summary Annual Report are financial and operating highlights and summary financial statements. For complete financial statements, including notes, please refer to the proxy statement for ExxonMobil's 2003 annual meeting. The proxy statement also includes management's discussion and analysis of financial condition and results of operations. We also make information available on the ExxonMobil Web site, exxonmobil.com. The ExxonMobil Web site contains the proxy statement and other company publications, including ExxonMobil's 2002 Financial and Operating Review, which provides additional details about the company's global operations.

Superior Returns to Shareholders

Industry-Leading Returns



*Competitor data estimated for 2002

Financial Highlights

Financial & Operating Highlights	2002	2001	2000	1999	1998
		(billions of dollars unless stated otherwise)			
Total Revenue	204.5	212.8	231.8	184.8	168.9
Net Income	11.5	15.3	17.7	7.9	8.1
Cash Flow from Operations and Asset Sales	24.1	24.0	28.7	16.0	18.3
Capital and Exploration Expenditures	14.0	12.3	11.2	13.3	15.5
Exploration Expenditures	1.3	1.7	1.5	1.9	2.2
Cash Dividends to ExxonMobil Shareholders	6.2	6.3	6.1	5.9	5.8
Research and Development Costs	0.6	0.6	0.6	0.6	0.8
Depreciation and Depletion Expense	8.3	7.8	8.0	8.2	8.2
Cash and Cash Equivalents at Year End	7.2	6.5	7.1	1.7	2.4
Total Assets at Year End	152.6	143.2	149.0	144.5	139.3
Total Debt at Year End	10.7	10.8	13.4	19.0	17.0
Shareholders' Equity at Year End	74.6	73.2	70.8	63.5	62.1
Average Capital Employed	88.3	88.0	87.5	83.8	80.1
Regular Employees at Year End *(thousands)*	92.5	97.9	99.6	106.9	111.6

Financial Ratios / Indicators					
Earnings per Share – Assuming Dilution *(dollars)*	1.68	2.21	2.52	1.12	1.14
Return on Average Capital Employed *(percent)*	13.5	17.8	20.6	10.3	10.7
Debt to Capital *(percent)*	12.2	12.4	15.4	22.0	20.6
Net Debt to Capital *(net of all cash - percent)*	4.4	5.3	7.9	20.4	18.2

ExxonMobil's long-term debt securities are rated AAA by Standard & Poor's and Aaa by Moody's, the highest credit ratings used by the rating agencies.

	Earnings After Income Taxes			*Capital and Exploration Expenditures*			*Average Capital Employed*			*Return on Average Capital Employed*		
Business Profile	2002	2001	2000	2002	2001	2000	2002	2001	2000	2002	2001	2000
				(millions of dollars)						*(percent)*		
Upstream												
United States	2,524	3,933	4,542	2,357	2,423	1,865	13,264	12,952	12,864	19.0	30.4	35.3
Non-U.S.	7,074	6,803	8,143	8,037	6,393	5,068	29,800	27,077	28,354	23.7	25.1	28.7
Total	9,598	10,736	12,685	10,394	8,816	6,933	43,064	40,029	41,218	22.3	26.8	30.8
Downstream												
United States	693	1,924	1,561	980	961	1,077	8,060	7,711	7,976	8.6	25.0	19.6
Non-U.S.	607	2,303	1,857	1,470	1,361	1,541	17,985	18,610	19,756	3.4	12.4	9.4
Total	1,300	4,227	3,418	2,450	2,322	2,618	26,045	26,321	27,732	5.0	16.1	12.3
Chemicals												
United States	384	398	644	575	432	351	5,235	5,506	5,644	7.3	7.2	11.4
Non-U.S.	446	484	517	379	440	1,117	8,410	8,333	8,170	5.3	5.8	6.3
Total	830	882	1,161	954	872	1,468	13,645	13,839	13,814	6.1	6.4	8.4
Corporate and Financing	(442)	(142)	(538)	77	158	52	4,878	6,399	3,198	–	–	–
Merger Expenses	(275)	(525)	(920)	–	–	–	–	–	–	–	–	–
Gain from Required Asset Divestitures	–	40	1,730	–	–	–	–	–	–	–	–	–
Discontinued Operations	449	102	184	80	143	97	710	1,412	1,501	63.2	7.2	12.3
ExxonMobil Total	11,460	15,320	17,720	13,955	12,311	11,168	88,342	88,000	87,463	13.5	17.8	20.6

Note: Prior periods amounts include reclassifications to reflect previously announced change in segment reporting. Earnings of divested coal and copper mining businesses are reported as discontinued operations.

For definitions of selected financial performance measures, see Frequently Used Terms on pages A4-A5 of ExxonMobil's 2003 Proxy Statement.

Shareholder Information

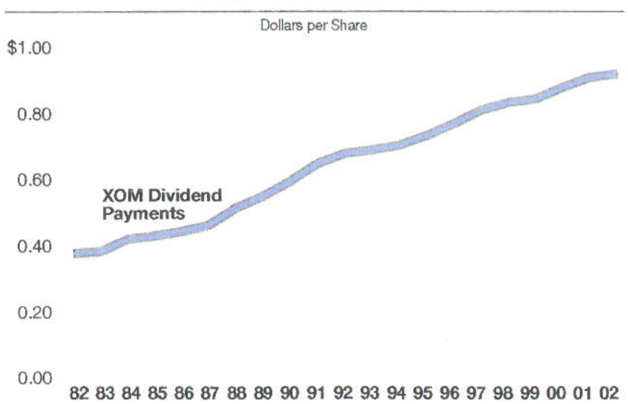
	2002	2001	2000	1999	1998
Net Income per Common Share *(dollars)*	1.69	2.23	2.55	1.14	1.15
Net Income per Common Share – Assuming Dilution *(dollars)*	1.68	2.21	2.52	1.12	1.14
Dividends per Common Share *(dollars)* (1)					
First Quarter	0.23	0.22	0.22	0.208	0.208
Second Quarter	0.23	0.23	0.22	0.208	0.208
Third Quarter	0.23	0.23	0.22	0.208	0.208
Fourth Quarter	0.23	0.23	0.22	0.220	0.209
Total	0.92	0.91	0.88	0.844	0.833
Number of Common Shares Outstanding *(millions)*					
Average	6,753	6,868	6,953	6,906	6,937
Average – Assuming Dilution	6,803	6,941	7,033	7,036	7,067
Year End	6,700	6,809	6,930	6,955	6,916
Annual Total Return to Shareholders *(percent)* (2)	(8.9)	(7.6)	10.2	12.5	22.4
Market Quotations for Common Stock *(dollars)* (3)					
High	44.58	45.84	47.72	43.63	38.66
Low	29.75	35.01	34.94	32.16	28.31
Average Daily Close	37.70	41.29	41.42	38.40	34.60
Year-end Close	34.94	39.30	43.47	40.28	36.57
Market Valuation at Year End *(millions of dollars)*	234,101	267,577	301,239	280,150	245,536

(1) Dividends per common share for 1998 and 1999 reflect the sum of the dividends paid by Exxon and Mobil divided by the number of shares that would have been outstanding for the periods, after adjusting the Mobil shares for the exchange ratio of 1.32015 shares of ExxonMobil common stock.

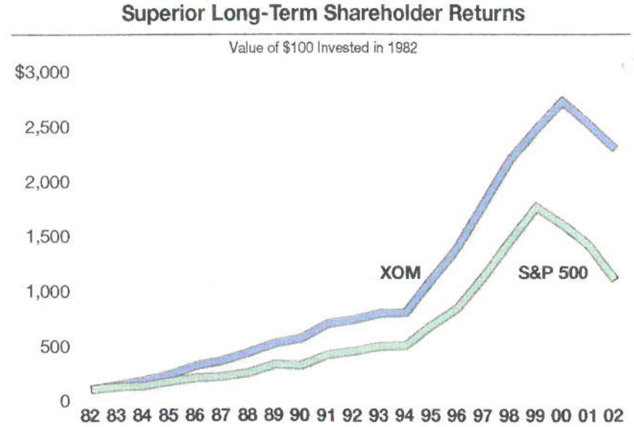
(2) Total return to shareholders is the appreciation of the stock price over a year plus the value of the dividends, with dividend reinvestment, and excluding trading commissions and taxes.

(3) Market quotations for common stock reflect Exxon share prices through November 30, 1999, the effective date of the merger, and ExxonMobil share prices thereafter.

Annual Dividend Payments Increased for 20th Consecutive Year



Superior Long-Term Shareholder Returns



Report of Independent Accountants

PRICEWATERHOUSECOOPERS

To the Shareholders of Exxon Mobil Corporation

In our report dated February 26, 2003, we express an unqualified opinion on the consolidated financial statements of Exxon Mobil Corporation and its subsidiary companies as of December 31, 2002 and 2001, and for each of the three years in the period ended December 31, 2002, appearing in Appendix A to the proxy statement for the 2003 annual meeting of shareholders of the Corporation (which statements are not presented herein). In our opinion, the information set forth in the accompanying summary balance sheets as of December 31, 2002 and 2001, and the related summary statement of income and cash flows for each of the three years in the period ended December 31, 2002, is fairly stated, in all material respects, in relation to the consolidated financial statements from which it has been derived.

Dallas, Texas
February 26, 2003

PricewaterhouseCoopers LLP

Summary of Accounting Policies and Practices

The corporation's accounting and financial reporting fairly reflect its straightforward business model involving the extracting, refining and marketing of hydrocarbons and hydrocarbon-based products. The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues, and expenses and the disclosure of contingent assets and liabilities. Actual results could differ from these estimates.

The summary financial statements include the accounts of those significant subsidiaries owned directly or indirectly with more than 50 percent of the voting rights held by the corporation, and for which other shareholders do not possess the right to participate in significant management decisions.

Revenues associated with sales of crude oil, natural gas, petroleum and chemical products and all other items are recorded when title passes to the customer.

The corporation makes limited use of derivative instruments to offset its economic exposures associated with interest rates, foreign currency exchange rates and hydrocarbon prices. Derivative instruments are recorded at fair value, and gains and losses arising from changes in fair value of those instruments are recorded in income. All derivatives activity is immaterial.

Inventories of crude oil, products and merchandise are carried at the lower of current market value or cost (generally determined under the last-in, first-out method — LIFO). Inventories of materials and supplies are valued at cost or less.

The corporation's exploration and production activities are accounted for under the "successful efforts" method. Depreciation, depletion and amortization, based on cost less estimated salvage value of the asset, are primarily determined under either the unit-of-production method or the straight-line method. Unit-of-production rates are based on oil, gas and other mineral reserves estimated to be recoverable from existing facilities. The straight-line method is based on estimated asset service life taking obsolescence into consideration.

Environmental conservation liabilities are recorded when it is probable that obligations have been incurred and the amounts can be reasonably estimated. Site restoration costs that may be incurred at the end of the operating life of certain facilities and properties are accrued ratably over the asset's productive life.

The "functional currency" for translating the accounts of the majority of downstream and chemical operations outside the U.S. is the local currency. Local currency is also used for upstream operations that are relatively self-contained and integrated within a particular country. The U.S. dollar is used for operations in highly inflationary economies and certain other countries.

Effective January 1, 2003, the fair value of future grants of employee stock-based awards will be recorded in compensation expense over the vesting period. For grants made prior to that date, no expense is recorded for stock option awards, but, for awards granted in the form of restricted stock, compensation expense based on the value of the shares on the date of grant is recorded over the vesting period.

Claims for substantial amounts have been made against ExxonMobil and certain of its consolidated subsidiaries in pending lawsuits. For further information on litigation and other contingencies, see note 17 on page A34 of ExxonMobil's 2003 Proxy Statement.

Further information on the corporation's accounting policies and practices can be found in ExxonMobil's 2003 Proxy Statement on pages A13-A15 (Critical Accounting Policies) and on pages A21-A22 (note 1 to the Financial Statements).

Summary Statement of Income

	2002	2001	2000
		(millions of dollars)	
Revenue			
Sales and other operating revenue, including excise taxes	200,949	208,715	227,596
Earnings from equity interests and other revenue	3,557	4,070	4,250
Total revenue	204,506	212,785	231,846
Costs and other deductions			
Crude oil and product purchases	90,950	92,257	108,913
Operating expenses	17,831	17,743	17,600
Selling, general and administrative expenses	12,356	12,898	12,044
Depreciation and depletion	8,310	7,848	8,001
Exploration expenses, including dry holes	920	1,175	936
Merger-related expenses	410	748	1,406
Interest expense	398	293	589
Excise taxes	22,040	21,907	22,356
Other taxes and duties	33,572	33,377	32,708
Income applicable to minority and preferred interests	209	569	412
Total costs and other deductions	186,996	188,815	204,965
Income before income taxes	17,510	23,970	26,881
Income taxes	6,499	8,967	11,075
Income from continuing operations	11,011	15,003	15,806
Discontinued operations, net of income tax	449	102	184
Extraordinary gain, net of income tax	–	215	1,730
Net income	11,460	15,320	17,720
Net income per common share *(dollars)*			
Income from continuing operations	1.62	2.19	2.27
Discontinued operations, net of income tax	0.07	0.01	0.03
Extraordinary gain, net of income tax	–	0.03	0.25
Net income	1.69	2.23	2.55
Net income per common share – assuming dilution *(dollars)*			
Income from continuing operations	1.61	2.17	2.24
Discontinued operations, net of income tax	0.07	0.01	0.03
Extraordinary gain, net of income tax	–	0.03	0.25
Net income	1.68	2.21	2.52

The information in the Summary Statement of Income shown above is a replication of the information in the Consolidated Statement of Income in ExxonMobil's 2003 Proxy Statement. Prior periods amounts include reclassifications to reflect previously announced change in segment reporting. Earnings of divested coal and copper mining businesses are reported as discontinued operations. For complete consolidated financial statements, including notes, please refer to pages A17 through A38 of ExxonMobil's 2003 Proxy Statement. See also management's discussion and analysis of financial condition and results of operations and other information on pages A2 through A16 of the 2003 Proxy Statement.

Summary Balance Sheet

	Dec. 31 2002	Dec. 31 2001
	(millions of dollars)	
Assets		
Current assets		
Cash and cash equivalents	7,229	6,547
Notes and accounts receivable, less estimated doubtful amounts	21,163	19,549
Inventories		
Crude oil, products and merchandise	6,827	6,743
Materials and supplies	1,241	1,161
Prepaid taxes and expenses	1,831	1,681
Total current assets	38,291	35,681
Investments and advances	12,111	10,768
Property, plant and equipment, at cost, less accumulated depreciation and depletion	94,940	89,602
Other assets, including intangibles, net	7,302	7,123
Total assets	152,644	143,174
Liabilities		
Current liabilities		
Notes and loans payable	4,093	3,703
Accounts payable and accrued liabilities	25,186	22,862
Income taxes payable	3,896	3,549
Total current liabilities	33,175	30,114
Long-term debt	6,655	7,099
Annuity reserves and accrued liabilities	16,454	12,475
Deferred income tax liabilities	16,484	16,359
Deferred credits and other long-term obligations	2,511	1,141
Equity of minority and preferred shareholders in affiliated companies	2,768	2,825
Total liabilities	78,047	70,013
Shareholders' equity		
Benefit plan related balances	(450)	(159)
Common stock without par value (9,000 million shares authorized)	4,217	3,789
Earnings reinvested	100,961	95,718
Accumulated other nonowner changes in equity		
Cumulative foreign exchange translation adjustment	(3,015)	(5,947)
Minimum pension liability adjustment	(2,960)	(535)
Unrealized gains/(losses) on stock investments	(79)	(108)
Common stock held in treasury (1,319 million shares in 2002 and 1,210 million shares in 2001)	(24,077)	(19,597)
Total shareholders' equity	74,597	73,161
Total liabilities and shareholders' equity	152,644	143,174

The information in the Summary Balance Sheet shown above is a replication of the information in the Consolidated Balance Sheet in ExxonMobil's 2003 Proxy Statement. For complete consolidated financial statements, including notes, please refer to pages A17 through A38 of ExxonMobil's 2003 Proxy Statement. See also management's discussion and analysis of financial condition and results of operations and other information on pages A2 through A16 of the 2003 Proxy Statement.

Summary Statement of Cash Flows

	2002	2001	2000
		(millions of dollars)	
Cash flows from operating activities			
Net income			
Accruing to ExxonMobil shareholders	11,460	15,320	17,720
Accruing to minority and preferred interests	209	569	412
Adjustments for non-cash transactions			
Depreciation and depletion	8,310	7,848	8,001
Deferred income tax charges/(credits)	297	650	10
Annuity and accrued liability provisions	(590)	498	(662)
Dividends received greater than/(less than) equity in current earnings of equity companies	(170)	78	(387)
Extraordinary gain, before income tax	–	(194)	(2,038)
Changes in operational working capital, excluding cash and debt			
Reduction/(increase) – Notes and accounts receivable	(305)	3,062	(4,832)
– Inventories	353	154	(297)
– Prepaid taxes and expenses	32	118	(204)
Increase/(reduction) – Accounts and other payables	365	(5,103)	5,411
All other items – net	1,307	(111)	(197)
Net cash provided by operating activities	21,268	22,889	22,937
Cash flows from investing activities			
Additions to property, plant and equipment	(11,437)	(9,989)	(8,446)
Sales of subsidiaries, investments and property, plant and equipment	2,793	1,078	5,770
Additional investments and advances	(2,012)	(1,035)	(1,648)
Collection of advances	898	1,735	985
Additions to other marketable securities	–	–	(41)
Sales of other marketable securities	–	–	82
Net cash used in investing activities	(9,758)	(8,211)	(3,298)
Net cash generation before financing activities	11,510	14,678	19,639
Cash flows from financing activities			
Additions to long-term debt	396	547	238
Reductions in long-term debt	(246)	(506)	(901)
Additions to short-term debt	751	705	500
Reductions in short-term debt	(927)	(1,212)	(2,413)
Additions/(reductions) in debt with less than 90-day maturity	(281)	(2,306)	(3,129)
Cash dividends to ExxonMobil shareholders	(6,217)	(6,254)	(6,123)
Cash dividends to minority interests	(169)	(194)	(251)
Changes in minority interests and sales/(purchases) of affiliate stock	(161)	(401)	(227)
Common stock acquired	(4,798)	(5,721)	(2,352)
Common stock sold	299	301	493
Net cash used in financing activities	(11,353)	(15,041)	(14,165)
Effects of exchange rate changes on cash	525	(170)	(82)
Increase/(decrease) in cash and cash equivalents	682	(533)	5,392
Cash and cash equivalents at beginning of year	6,547	7,080	1,688
Cash and cash equivalents at end of year	7,229	6,547	7,080

The information in the Summary Statement of Cash Flows shown above is a replication of the information in the Consolidated Statement of Cash Flows in ExxonMobil's 2003 Proxy Statement. For complete consolidated financial statements, including notes, please refer to pages A17 through A38 of ExxonMobil's 2003 Proxy Statement. See also management's discussion and analysis of financial condition and results of operations and other information on pages A2 through A16 of the 2003 Proxy Statement.

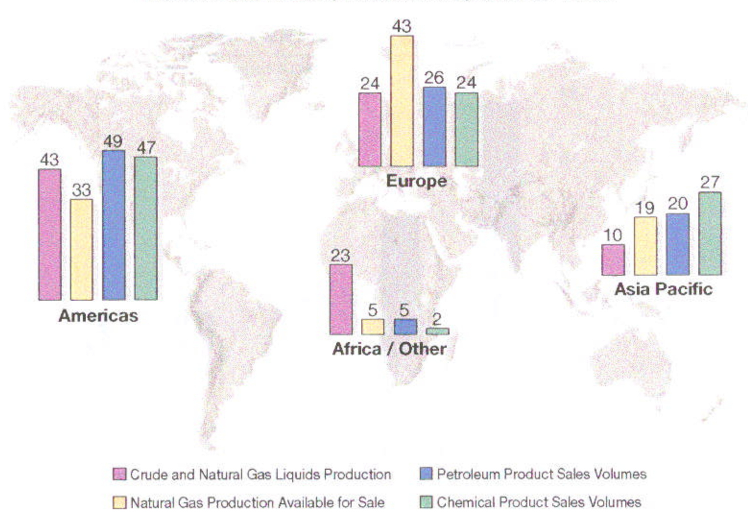
Volumes Summary

	2002	2001	2000	1999	1998
Net Production of Crude Oil and Natural Gas Liquids		*(thousands of barrels per day)*			
United States	681	712	733	729	745
Non-U.S.	1,815	1,830	1,820	1,788	1,757
Worldwide Total	2,496	2,542	2,553	2,517	2,502
Net Natural Gas Production Available For Sale		*(millions of cubic feet per day)*			
United States	2,375	2,598	2,856	2,871	3,140
Non-U.S.	8,077	7,681	7,487	7,437	7,477
Worldwide Total	10,452	10,279	10,343	10,308	10,617
		(thousands of oil-equivalent barrels daily)			
Oil-Equivalent Production*	4,238	4,255	4,277	4,235	4,272
Refinery Throughput		*(thousands of barrels per day)*			
United States	1,871	1,840	1,862	1,930	1,919
Non-U.S.	3,610	3,731	3,780	4,047	4,174
Worldwide Total	5,481	5,571	5,642	5,977	6,093
Petroleum Product Sales					
United States	2,731	2,751	2,669	2,918	2,804
Non-U.S.	5,026	5,220	5,324	5,969	6,069
Worldwide Total	7,757	7,971	7,993	8,887	8,873
Gasoline, Naphthas	3,176	3,165	3,122	3,428	3,417
Heating Oils, Kerosene, Diesel	2,292	2,389	2,373	2,658	2,689
Aviation Fuels	691	721	749	813	774
Heavy Fuels	604	668	694	706	765
Specialty Products	994	1,028	1,055	1,282	1,228
Worldwide Total	7,757	7,971	7,993	8,887	8,873
Chemical Prime Product Sales		*(thousands of metric tons)*			
United States	11,386	11,078	11,736	11,719	11,231
Non-U.S.	15,539	14,702	13,901	13,564	12,397
Worldwide Total	26,925	25,780	25,637	25,283	23,628

** Gas converted to oil equivalent at 6 million cubic feet = 1 thousand barrels.*

Functional and Geographic Diversity – A Core Strength of ExxonMobil

Relative Contribution in 2002 by Functional and Geographic Areas – Percent



ExxonMobil operates in about 200 countries and territories around the world. The company's global reach, scale, and functional and geographic diversity are core strengths. The colored bars at left represent the percentage of ExxonMobil's crude and natural gas liquids production, natural gas production, petroleum product sales and chemical product sales in each of the regions shown.

Reserves Summary

	2002	2001	2000	1999	1998
Crude Oil and Natural Gas Liquids		*(millions of barrels at year end)*			
Net Proved Developed and Undeveloped Reserves					
United States	3,352	3,494	3,480	3,285	3,381
Canada *	1,285	1,277	1,330	1,355	1,154
Europe	1,359	1,503	1,591	1,797	1,747
Asia Pacific	691	622	690	715	786
Africa	2,626	2,461	2,384	2,024	1,821
Other Non-U.S.	2,510	2,134	2,086	2,084	2,064
Worldwide Total *	11,823	11,491	11,561	11,260	10,953
Natural Gas		*(billions of cubic feet at year end)*			
Net Proved Developed and Undeveloped Reserves					
United States	12,239	12,924	13,296	13,227	13,224
Canada	2,882	3,183	3,516	3,387	3,489
Europe	24,336	25,252	26,017	26,454	27,071
Asia Pacific	7,958	8,301	8,546	9,358	9,998
Africa	436	379	375	171	113
Other Non-U.S.	7,867	5,907	4,116	4,199	4,111
Worldwide Total	55,718	55,946	55,866	56,796	58,006
Proved Reserves Replacement Ratio *(percent)* *(excluding tar sands and excluding asset sales)*	120	98	110	108	134
Proved Reserves Replacement Ratio *(percent)* *(including tar sands and excluding asset sales)*	118	111	112	106	132

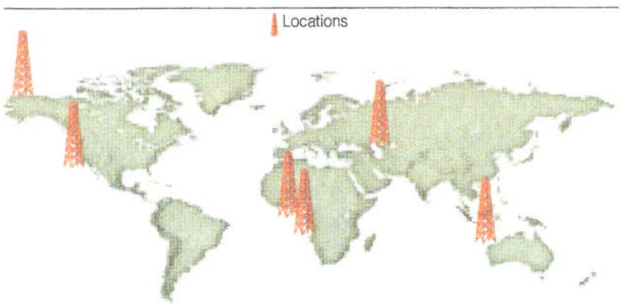
Proved oil and gas reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions. In some cases, substantial new investments in additional wells and related facilities will be required to recover these proved reserves.

Proved reserves include 100 percent of each majority-owned affiliate's participation in proved reserves and ExxonMobil's ownership percentage of the proved reserves of equity companies, but exclude royalties and quantities due others. Gas reserves exclude the gaseous equivalent of liquids expected to be removed from the gas on leases, at field facilities and at gas processing plants. These liquids are included in net proved reserves of crude oil and natural gas liquids.

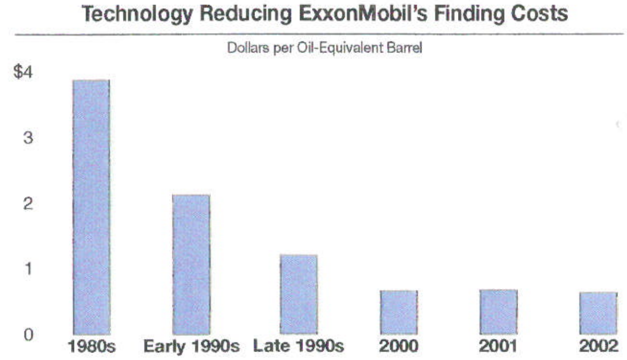
*Information on Canadian tar sands proven reserves is not included in the tabular volumes above because the U.S. Securities and Exchange Commission regulations define these reserves as mining-related and not a part of conventional liquids reserves. ExxonMobil views these reserves and their development as an integral part of total upstream operations. Canadian tar sands reserves, not included in the tabular data above, totaled 800 million barrels at year-end 2002, 821 million barrels at year-end 2001, 610 million barrels at year-end 2000, 577 million barrels at year-end 1999, and 597 million barrels at year-end 1998.

Exploration Success Fueling Profitable Growth

Major Resource Additions in 2002



Technology Reducing ExxonMobil's Finding Costs



ExxonMobil was successful in adding 2.2 billion oil-equivalent barrels to its industry-leading 72 billion oil-equivalent barrel resource base. This year, significant, high-quality resource additions were delivered from numerous discoveries in the growth areas of West Africa and the Caspian, as well as Australia and the United States. Finding costs in 2002 were 61 cents per oil-equivalent barrel. Note that terms such as "resources," "resource base," "recoverable hydrocarbons," and similar terms used in this report include quantities of oil and gas that are not yet classified as proved reserves, but which ExxonMobil believes will likely be moved into the proved reserves category and produced in the future.

Directors, Officers and Affiliated Companies

From left to right: Philip E. Lippincott, Helene L. Kaplan, Marilyn Carlson Nelson, Walter V. Shipley, Michael J. Boskin, Lee R. Raymond, Donald V. Fites, James R. Houghton, Harry J. Longwell, Henry A. McKinnell, Jr., Reatha Clark King, William T. Esrey, William R. Howell

Directors

Michael J. Boskin . . . . *T.M. Friedman Professor of Economics and Senior Fellow*, Hoover Institution, Stanford University

William T. Esrey . . . . *Chairman and Chief Executive Officer*, Sprint Corporation [global communications company integrating long-distance, local and wireless communications services and one of the world's largest carriers of Internet traffic]

Donald V. Fites . . . . *Former Chairman and Chief Executive Officer*, Caterpillar Inc. [manufacturer of heavy machinery]

James R. Houghton . . . . . *Chairman of the Board and Chief Executive Officer*, Corning Incorporated [communications, advanced materials and display products]

William R. Howell . . . . . . *Chairman Emeritus*, J.C. Penney Company, Inc. [department store and catalog chain]

Helene L. Kaplan . . . . *Of Counsel*, Skadden, Arps, Slate, Meagher & Flom LLP [law firm]

Reatha Clark King . . . . . . *Chairman of the Board of Trustees*, General Mills Foundation [manufacturer and marketer of consumer food products]

Philip E. Lippincott . . . . . . *Retired Chairman of the Board*, Campbell Soup Company [global manufacturer and marketer of high-quality, branded convenience food products]; *Retired Chairman and Chief Executive Officer*, Scott Paper Company [sanitary paper, printing and publishing papers and forestry operations]

Harry J. Longwell. . . . . . . *Executive Vice President*

Henry A. McKinnell, Jr. . . . . *Chairman of the Board and Chief Executive Officer*, Pfizer, Inc. [research-based pharmaceutical company]

Marilyn Carlson Nelson. . . . *Chairman and Chief Executive Officer*, Carlson Companies, Inc.; *Co-Chair*, Carlson Holdings, Inc. [travel, hotels, restaurants and marketing services]

Lee R. Raymond . . . . *Chairman and Chief Executive Officer*

Walter V. Shipley . . . . *Retired Chairman of the Board*, The Chase Manhattan Corporation and The Chase Manhattan Bank [banking and finance]

Directors, Officers and Affiliated Companies (continued)

Standing Committees of the Board

Board Audit Committee . . . . . J.R. Houghton *(Chairman),* W.T. Esrey, W.R. Howell, H.L. Kaplan, R.C. King, M.C. Nelson

Board Advisory Committee on Contributions . . . . M.J. Boskin *(Chairman)*, W.T. Esrey, H.L. Kaplan, R.C. King, P.E. Lippincott, M.C. Nelson

Board Affairs Committee . . . . . M.C. Nelson *(Chairman),* D.V. Fites, W.R. Howell, P.E. Lippincott, H.A. McKinnell, Jr., W.V. Shipley

Board Compensation Committee . . . . W.R. Howell *(Chairman),* M.J. Boskin, W.T. Esrey, J.R. Houghton, R.C. King, H.A. McKinnell, Jr.

Finance Committee . . . . L.R. Raymond *(Chairman)*, M.J. Boskin, D.V. Fites, J.R. Houghton, H.A. McKinnell, Jr., W.V. Shipley

Public Issues Committee . . . . . P.E. Lippincott *(Chairman),* D.V. Fites, H.L. Kaplan, W.V. Shipley

Executive Committee . . . . L.R. Raymond *(Chairman),* J.R. Houghton, W.R. Howell, P.E. Lippincott, M.C. Nelson

Officers

L.R. Raymond . . . . *Chairman of the Board**
H.J. Longwell . . . . *Executive Vice President**
E.G. Galante . . . . *Senior Vice President**
R.W. Tillerson . . . . *Senior Vice President**
L.J. Cavanaugh . . . . *Vice President-Human Resources*
K.P. Cohen . . . . *Vice President-Public Affairs*
H.R. Cramer . . . . *Vice President**
J.V. Genova . . . . *General Manager-Corporate Planning*
D.D. Humphreys . . . . *Vice President and Controller**
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C.W. Matthews . . . . *Vice President and General Counsel**
S.R. McGill . . . . *Vice President**
P.T. Mulva . . . . *Vice President-Investor Relations and Secretary**
F.A. Risch . . . . *Vice President and Treasurer**
J.J. Rouse . . . . *Vice President-Washington Office*
D.S. Sanders . . . . *Vice President**
J.S. Simon . . . . *Vice President**
F.B. Sprow . . . . *Vice President-Safety, Health and Environment*
P.E. Sullivan . . . . *Vice President and General Tax Counsel**
J.L. Thompson . . . . *Vice President**

Functional and Service Organizations

Upstream

J.L. Thompson . . . . . *President, ExxonMobil Exploration Company**
M.E. Foster . . . . *President, ExxonMobil Development Company**
K.T. Koonce . . . . . . *President, ExxonMobil Production Company**
S.R. McGill . . . . *President, ExxonMobil Gas & Power Marketing Company**
S.M. Cassiani . . . . . . *President, ExxonMobil Upstream Research Company; President, ExxonMobil Upstream Technical Computing Company*

Downstream

J.S. Simon . . . . *President, ExxonMobil Refining & Supply Company**
H.R. Cramer . . . . . . *President, ExxonMobil Fuels Marketing Company**
G.L. Kohlenberger . . . *President, ExxonMobil Lubricants & Petroleum Specialties Company**
W.R.K. Innes . . . . . . *President, ExxonMobil Research and Engineering Company*

Chemical

D.S. Sanders . . . . . . *President, ExxonMobil Chemical Company**

Other

T.J. Hearn . . . . *Chairman of the Board, Imperial Oil Limited*
S.J. Glass, Jr. . . . . . . *President, ExxonMobil Global Services Company*

**Required to file reports under Section 16 of the Securities Exchange Act of 1934.*

Investor Information

ExxonMobil offers its shareholders a wide range of services and several ways to access important company information.

ExxonMobil on the Internet

A Quick, Easy Way to Get Information About ExxonMobil

ExxonMobil company publications and important shareholder information are available on the Internet at exxonmobil.com

Your Online Source For:

- Shareholder Publications
- Current Stock Price
- Dividend Information
- Contact Information
- Shareholder Investment Program
- Press Releases

Shareholder Services

Shareholder inquiries should be addressed to ExxonMobil Shareholder Services at EquiServe Trust Company, N.A., ExxonMobil's transfer agent:

ExxonMobil Shareholder Services
P.O. Box 43008
Providence, RI 02940-3008

1-800-252-1800
(Within the continental U.S.)

1-781-575-2058
(Outside the continental U.S.)

An automated voice-response system is available 24 hours a day, 7 days a week. Service representatives are available during normal business hours.

Registered shareholders can access information about their ExxonMobil stock accounts via the Internet at equiserve.com.

Electronic Payment of Dividends

Shareholders may have their dividends deposited directly into their bank accounts. If you'd like to elect this option, go to equiserve.com or call or write ExxonMobil Shareholder Services for an authorization form.

Shareholder Investment Program

ExxonMobil's Shareholder Investment Program (SIP) allows participants to purchase ExxonMobil stock and reinvest dividends directly without contacting a broker. You do not have to be a shareholder to enroll. For more information and a prospectus, go to exxonmobil.com or call or write ExxonMobil Shareholder Services. We currently expect to purchase all SIP shares in the open market. As a result, ExxonMobil will receive no proceeds.

Duplicate Annual Reports

Shareholders may eliminate duplicate report mailings by marking their proxy card or by writing or calling ExxonMobil Shareholder Services.

ExxonMobil Publications

The publications listed below, all of which can be found on our Internet site at exxonmobil.com, are available without charge to shareholders. Requests for printed copies should be directed to ExxonMobil Shareholder Services.

2002 Summary Annual Report

2002 Annual Report on Form 10-K

2002 Financial and Operating Review, a report on ExxonMobil's businesses, strategies and results

Corporate Citizenship Report

The Lamp, a quarterly shareholder magazine with news and features about ExxonMobil's worldwide activities

General Information

Addresses

Corporate Headquarters
Exxon Mobil Corporation
5959 Las Colinas Boulevard
Irving, TX 75039-2298

Shareholder Relations
Exxon Mobil Corporation
P.O. Box 140369
Irving, TX 75014-0369

Market Information

The New York Stock Exchange is the principal exchange on which Exxon Mobil Corporation common stock (symbol XOM) is traded.

Annual Meeting

The 2003 Annual Meeting of Shareholders will be held at 9:00 a.m. central time on Wednesday, May 28, at:

The Morton H. Meyerson Symphony Center
2301 Flora Street
Dallas, Texas 75201

The meeting will be audiocast live on the Internet. Instructions for listening to this audiocast will be available on the Internet at exxonmobil.com approximately one week prior to the event.

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Table 7

Conventional Natural Gas Resource Base for Alaska as of 2000

(Risked, Undiscovered, Conventionally Recoverable; Excludes Coalbed Gas and Gas Hydrates)

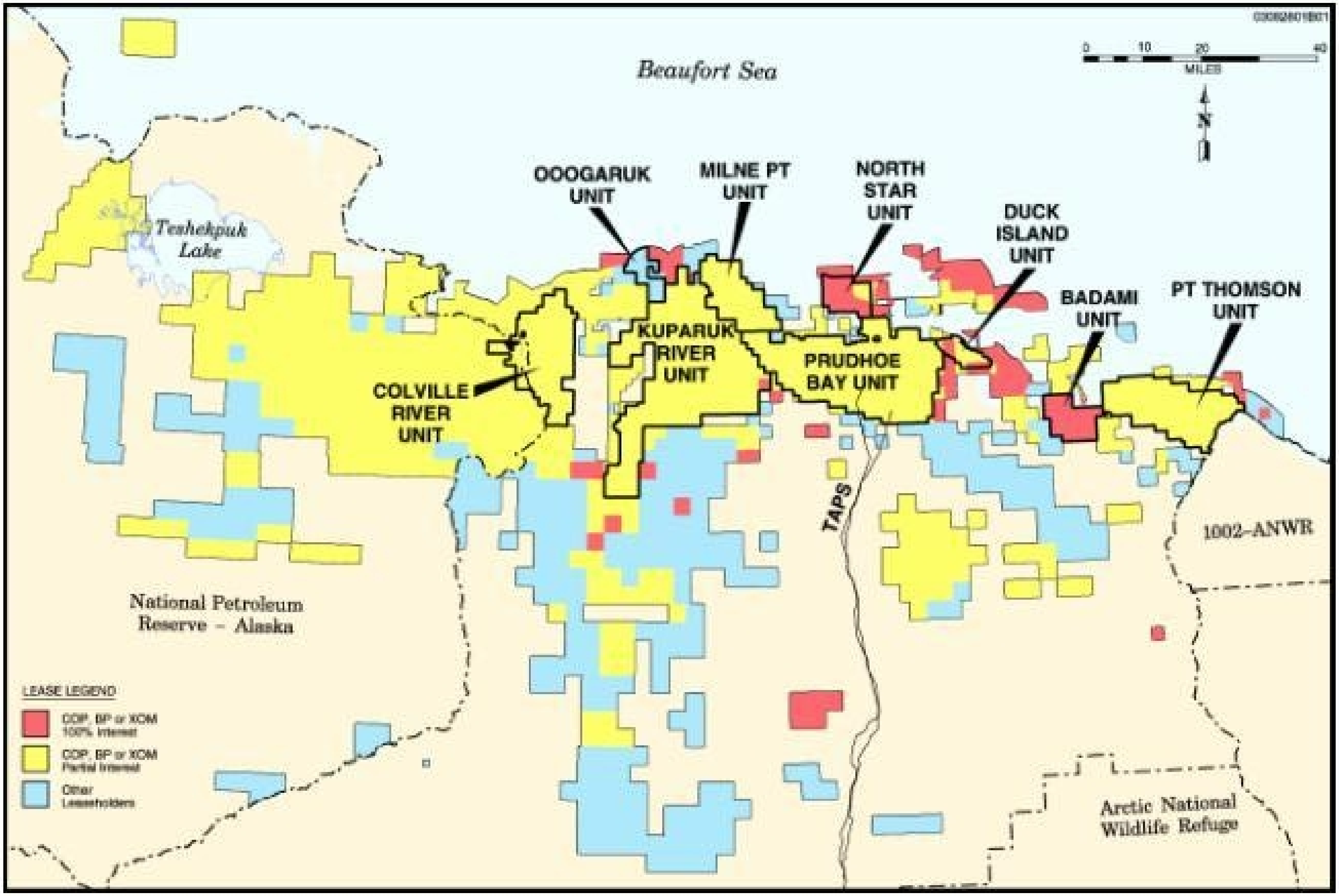
Area	F95[15] (tcf)	Mean (tcf)	F05[15] (tcf)	Area Chance[16]
Arctic Alaska				
Northern Alaska[1]	23.3	63.5[3]	124.3	1.0[1]
Beaufort shelf[2]	12.86	32.07[4]	63.27	1.0[2]
Chukchi shelf[2]	13.56	60.11[5]	154.31	1.0[2]
Subtotal[15]		155.68[6]		
Bering Shelf, Hope Basin, and Central Alaska				
Hope basin (offshore)[2]	0.0	3.38[7]	11.06	0.61[2]
Bering shelf[2]				
Navarin basin	0.0	6.15	18.18	0.88
North Aleutian basin	0.0	6.79[8]	17.33	0.72
St. George basin	0.0	3.00	9.72	0.94
Norton basin	0.0	2.71	8.74	0.72
St. Matthew-Hall basin	0.0	0.16	0.69	0.44
Central Alaska[1]	0.5	2.8[9]	7.3	1.0[1]
Subtotal[15]		24.99		
Pacific Margin and Southern Alaska				
Southern Alaska (mostly Cook Inlet-State of Alaska Lands)[1]	0.7	2.1[10]	4.3	1.0[1]
Cook Inlet (Federal Offshore)[2]	0.66	1.39[11]	2.49	1.0[2]
Gulf of Alaska (Federal Offshore)[2]	0.94	4.18[12]	10.59	0.99[2]
Shumagin-Kodiak shelf[2]	0.0	2.65[13]	11.35	0.4[2]
Subtotal[15]		10.32		
Subtotal for Alaska Federal Offshore		122.59		
Subtotal for Alaska Onshore		68.4		
Total Undiscovered Gas Potential for Alaska[15]		***190.99[14]***		

[1] USGS, 1995, tbl. 2, and CD DDS-36, *region1\convtab.tab*
[2] Craig (2000)
[3] estimated at 68.2 tcf by PGC (1997, tbl. 55 and 1999, tbl. 52)
[4] estimated at 33.5 tcf by PGC (1999, tbl. 53)
[5] estimated at 19.5 tcf by PGC
[6] estimated at 121.2 tcf by PGC
[7] estimated at 0.6 tcf by PGC
[8] estimated at 6.5 tcf by PGC
[9] PGC (1999, tbl. 52) estimate for "Interior Basins" province = 0.5 tcf
[10] PGC estimate for "Cook Inlet-Susitna" province = 4.5 tcf
[11] estimated at 2.1 tcf by PGC (1999, tbl. 53)
[12] PGC (1999, tbl. 53) estimates for "N. Gulf of Alaska Shelf" and "Southeastern Alaska Shelf" provinces sum to 1.7 tcf
[13] estimated at 1.7 tcf by PGC (1999, tbl. 53)
[14] PGC (1999, tbl. 53) total for Alaska = 143.1 tcf
[15] Fractile values (F95, F05 gas quantities) are not additive. F05 represents a 1 in 20 (or 5%) chance that the indicated gas quantity will be exceeded. Mean values may be added.
[16] chance that the area contains at least one pool of oil or gas capable of flowing to a conventional wellbore

na: not available
tcf: trillion cubic feet

Appendix A.5 | North Slope Units Map

North Slope Units



Appendix A.6	Description of Leases within Existing Units

Listing of North Slope Leases

DESCRIPTION OF LEASES WITHIN EXISTING UNITS (APPENDIX A.6)

Effective September 15, 2003

	AGENCY		NOTIFICATION LESSEE		OTHER WIO		OTHER WIO		OTHER WIO					NET	
UNIT	LEASE NO	LESSOR	NAME	WI	NAME	WI	NAME	WI	NAME	WI	EXPIRATION	ACRES	ROYALTY	PROFIT	SLIDING
BADAMI	ADL365533	ALASKA	BPXA	100.0000000							11/30/1995	5120.00	16.667	N	N
BADAMI	ADL365535	ALASKA	BPXA	100.0000000							11/30/1995	3840.00	16.667	N	N
BADAMI	ADL367004	ALASKA	BPXA	100.0000000							04/30/1996	3840.00	12.500	N	N
BADAMI	ADL367005	ALASKA	BPXA	100.0000000							04/30/1996	3840.00	12.500	N	N
BADAMI	ADL367006	ALASKA	BPXA	100.0000000							04/30/1996	5035.00	12.500	N	N
BADAMI	ADL367010	ALASKA	BPXA	100.0000000							04/30/1996	3840.00	12.500	N	N
BADAMI	ADL367011	ALASKA	BPXA	100.0000000							04/30/1996	2533.00	12.500	N	N
BADAMI	ADL375093	ALASKA	BPXA	100.0000000							03/31/2001	1280.00	12.500	N	N
BADAMI	ADL375094	ALASKA	BPXA	100.0000000							03/31/2001	2544.00	12.500	N	N
BADAMI	ADL377011	ALASKA	BPXA	100.0000000							07/31/2001	5529.92	16.667	N	N

	AGENCY		NOTIFICATION LESSEE		OTHER WIO		OTHER WIO		OTHER WIO					NET	
UNIT	LEASE NO	LESSOR	NAME	WI	NAME	WI	NAME	WI	NAME	WI	EXPIRATION	ACRES	ROYALTY	PROFIT	SLIDING
COLVILLE RIVER	ADL025526	ALASKA	CPAI	56.0000000	APC	22.0000000	PAAI	22.0000000			11/11/2000	2295.36	12.500	N	N
COLVILLE RIVER	ADL025529	ALASKA	CPAI	56.0000000	PAAI	22.0000000	APC	22.0000000			11/11/2000	986.19	12.500	N	N
COLVILLE RIVER	ADL025530	ALASKA	CPAI	56.0000000	PAAI	22.0000000	APC	22.0000000			11/11/2000	2588.97	12.500	N	N
COLVILLE RIVER	ADL025538	ALASKA	CPAI	56.0000000	APC	22.0000000	PAAI	22.0000000			01/31/1975	2448.00	12.500	N	N
COLVILLE RIVER	ADL025557	ALASKA	CPAI	56.0000000	PAAI	22.0000000	APC	22.0000000			01/31/1975	2560.00	12.500	N	N
COLVILLE RIVER	ADL025558	ALASKA	CPAI	56.0000000	APC	22.0000000	PAAI	22.0000000			01/31/1975	2459.00	5.000	N	N
COLVILLE RIVER	ADL025559	ALASKA	CPAI	56.0000000	PAAI	22.0000000	APC	22.0000000			01/31/1975	2469.00	12.500	N	N
COLVILLE RIVER	ADL025560	ALASKA	CPAI	56.0000000	PAAI	22.0000000	APC	22.0000000			11/11/2002	2560.00	12.500	N	N
COLVILLE RIVER	ADL364470	ALASKA	CPAI	56.0000000	PAAI	22.0000000	APC	22.0000000			07/31/1994	3180.00	12.500	30.000	N
COLVILLE RIVER	ADL364471	ALASKA	CPAI	56.0000000	APC	22.0000000	PAAI	22.0000000			07/31/1994	5759.00	12.500	30.000	N
COLVILLE RIVER	ADL364472	ALASKA	CPAI	56.0000000	PAAI	22.0000000	APC	22.0000000			07/31/1994	4480.00	12.500	30.000	N
COLVILLE RIVER	ADL372095	ALASKA	CPAI	56.0000000	PAAI	22.0000000	APC	22.0000000			03/31/1998	2560.00	12.500	N	N
COLVILLE RIVER	ADL372096	ALASKA	CPAI	56.0000000	PAAI	22.0000000	APC	22.0000000			03/31/1998	640.00	12.500	N	N
COLVILLE RIVER	ADL372097	ALASKA	CPAI	56.0000000	PAAI	22.0000000	APC	22.0000000			03/31/1998	1239.00	12.500	N	N
COLVILLE RIVER	ADL372103	ALASKA	CPAI	56.0000000	APC	22.0000000	PAAI	22.0000000			03/31/1998	2560.00	12.500	N	N
COLVILLE RIVER	ADL372104	ALASKA	CPAI	56.0000000	PAAI	22.0000000	APC	22.0000000			03/31/1998	2560.00	12.500	N	N
COLVILLE RIVER	ADL372105	ALASKA	CPAI	56.0000000	PAAI	22.0000000	APC	22.0000000			03/31/1998	2437.00	12.500	N	N
COLVILLE RIVER	ADL372106	ALASKA	CPAI	56.0000000	PAAI	22.0000000	APC	22.0000000			03/31/1998	1920.00	12.500	N	N
COLVILLE RIVER	ADL372107	ALASKA	CPAI	56.0000000	PAAI	22.0000000	APC	22.0000000			03/31/1998	2560.00	12.500	N	N
COLVILLE RIVER	ADL372108	ALASKA	CPAI	56.0000000	PAAI	22.0000000	APC	22.0000000			03/31/1998	1280.00	12.500	N	N
COLVILLE RIVER	ADL380042	ALASKA	CPAI	56.0000000	APC	22.0000000	PAAI	22.0000000			01/31/2003	1280.00	16.667	N	N
COLVILLE RIVER	ADL380043	ALASKA	CPAI	56.0000000	PAAI	22.0000000	APC	22.0000000			01/31/2003	2560.00	16.667	N	N
COLVILLE RIVER	ADL380044	ALASKA	CPAI	56.0000000	APC	22.0000000	PAAI	22.0000000			01/31/2003	2035.27	16.667	N	N
COLVILLE RIVER	ADL380045	ALASKA	CPAI	56.0000000	APC	22.0000000	PAAI	22.0000000			01/31/2003	1280.00	16.667	N	N
COLVILLE RIVER	ADL380046	ALASKA	CPAI	56.0000000	PAAI	22.0000000	APC	22.0000000			01/31/2003	2150.45	16.667	N	N
COLVILLE RIVER	ADL380048	ALASKA	CPAI	56.0000000	PAAI	22.0000000	APC	22.0000000			01/31/2003	1716.41	16.667	N	N
COLVILLE RIVER	ADL380075	ALASKA	CPAI	56.0000000	APC	22.0000000	PAAI	22.0000000			01/31/2003	4396.59	16.667	N	N
COLVILLE RIVER	ADL380077	ALASKA	CPAI	56.0000000	PAAI	22.0000000	APC	22.0000000			01/31/2003	2148.81	16.667	N	N
COLVILLE RIVER	ADL380078	ALASKA	CPAI	56.0000000	PAAI	22.0000000	APC	22.0000000			01/31/2003	1920.00	16.667	N	N
COLVILLE RIVER	ADL380079	ALASKA	CPAI	56.0000000	PAAI	22.0000000	APC	22.0000000			01/31/2003	640.00	16.667	N	N
COLVILLE RIVER	ADL380080	ALASKA	CPAI	56.0000000	APC	22.0000000	PAAI	22.0000000			01/31/2003	1920.00	16.667	N	N
COLVILLE RIVER	ADL380081	ALASKA	CPAI	56.0000000	PAAI	22.0000000	APC	22.0000000			01/31/2003	2560.00	16.667	N	N
COLVILLE RIVER	ADL380082	ALASKA	CPAI	56.0000000	APC	22.0000000	PAAI	22.0000000			01/31/2003	640.00	16.667	N	N
COLVILLE RIVER	ADL380092	ALASKA	CPAI	56.0000000	PAAI	22.0000000	APC	22.0000000			01/31/2003	1516.00	16.667	N	N
COLVILLE RIVER	ADL380093	ALASKA	CPAI	56.0000000	PAAI	22.0000000	APC	22.0000000			01/31/2003	1426.64	16.667	N	N
COLVILLE RIVER	ADL380095	ALASKA	CPAI	56.0000000	PAAI	22.0000000	APC	22.0000000			01/31/2003	498.08	16.667	N	N
COLVILLE RIVER	ADL380096	ALASKA	CPAI	56.0000000	PAAI	22.0000000	APC	22.0000000			01/31/2003	640.00	16.667	N	N
COLVILLE RIVER	ADL384202	ALASKA	CPAI	55.6200000	PAAI	22.0000000	APC	22.0000000	PETRO-HUNT	0.3800000	10/31/2003	1280.00	16.667	N	N
COLVILLE RIVER	ADL384203	ALASKA	CPAI	56.0000000	PAAI	22.0000000	APC	22.0000000			10/31/2003	896.32	16.667	N	N
COLVILLE RIVER	ADL384204	ALASKA	CPAI	55.6200000	PAAI	22.0000000	APC	22.0000000	PETRO-HUNT	0.3800000	10/31/2003	1280.00	16.667	N	N
COLVILLE RIVER	ADL384205	ALASKA	CPAI	56.0000000	PAAI	22.0000000	APC	22.0000000			10/31/2003	640.00	16.667	N	N
COLVILLE RIVER	ADL384206	ALASKA	CPAI	56.0000000	PAAI	22.0000000	APC	22.0000000			10/31/2003	1280.00	16.667	N	N
COLVILLE RIVER	ADL384209	ALASKA	CPAI	56.0000000	PAAI	22.0000000	APC	22.0000000			10/31/2003	640.00	16.667	N	N
COLVILLE RIVER	ADL384210	ALASKA	CPAI	56.0000000	APC	22.0000000	PAAI	22.0000000			10/31/2003	1280.00	16.667	N	N
COLVILLE RIVER	ADL384211	ALASKA	CPAI	56.0000000	APC	22.0000000	PAAI	22.0000000			10/31/2003	2485.00	16.667	N	N
COLVILLE RIVER	ADL384214	ALASKA	CPAI	56.0000000	PAAI	22.0000000	APC	22.0000000			10/31/2003	1920.00	16.667	N	N
COLVILLE RIVER	ADL384215	ALASKA	CPAI	55.6200000	PAAI	22.0000000	APC	22.0000000	PETRO-HUNT	0.3800000	10/31/2003	597.00	16.667	N	N
COLVILLE RIVER	ADL387207	ALASKA	CPAI	56.0000000	APC	22.0000000	PAAI	22.0000000			09/30/2003	1269.00	16.667	N	33.000
COLVILLE RIVER	ADL387208	ALASKA	CPAI	56.0000000	PAAI	22.0000000	APC	22.0000000			09/30/2003	1145.67	16.667	N	33.000
COLVILLE RIVER	ADL387209	ALASKA	CPAI	56.0000000	APC	22.0000000	PAAI	22.0000000			09/30/2003	639.93	16.667	N	33.000
COLVILLE RIVER	ADL387211	ALASKA	CPAI	56.0000000	PAAI	22.0000000	APC	22.0000000			09/30/2003	1039.78	16.667	N	N
COLVILLE RIVER	ADL387212	ALASKA	CPAI	56.0000000	APC	22.0000000	PAAI	22.0000000			09/30/2003	1251.03	16.667	N	33.000
COLVILLE RIVER	ADL388525	ALASKA	CPAI	56.0000000	PAAI	22.0000000	APC	22.0000000			12/31/2004	384.00	16.667	N	N

	AGENCY		NOTIFICATION LESSEE		OTHER WIO		OTHER WIO		OTHER WIO					NET	
UNIT	LEASE NO	LESSOR	NAME	WI	NAME	WI	NAME	WI	NAME	WI	EXPIRATION	ACRES	ROYALTY	PROFIT	SLIDING
COLVILLE RIVER	ADL388527	ALASKA	CPAI	56.0000000	PAAI	22.0000000	APC	22.0000000			12/31/2004	572.00	16.667	N	N
COLVILLE RIVER	ADL388528	ALASKA	CPAI	56.0000000	PAAI	22.0000000	APC	22.0000000			12/31/2004	420.00	16.667	N	N
COLVILLE RIVER	ADL388529	ALASKA	CPAI	56.0000000	APC	22.0000000	PAAI	22.0000000			12/31/2004	362.00	16.667	N	N
COLVILLE RIVER	ADL388901	ALASKA	CPAI	56.0000000	PAAI	22.0000000	APC	22.0000000			11/11/2000	1038.55	12.500	N	N
COLVILLE RIVER	ADL388902	ALASKA	CPAI	56.0000000	PAAI	22.0000000	APC	22.0000000			01/31/2003	1892.63	16.667	N	N
COLVILLE RIVER	ADL388903	ALASKA	CPAI	56.0000000	PAAI	22.0000000	APC	22.0000000			01/31/2003	1247.00	16.667	N	N
COLVILLE RIVER	ADL388904	ALASKA	CPAI	56.0000000	APC	22.0000000	PAAI	22.0000000			01/31/2003	652.73	16.667	N	N
COLVILLE RIVER	ADL388905	ALASKA	CPAI	56.0000000	APC	22.0000000	PAAI	22.0000000			09/30/2003	286.63	16.667		33.000
COLVILLE RIVER	ADL388906	ALASKA	CPAI	56.0000000	PAAI	22.0000000	APC	22.0000000			09/30/2003	24.74	16.667	N	N
COLVILLE RIVER	ADL389113	ALASKA	CPAI	78.0000000	APC	22.0000000					10/31/2005	640.00	12.500	N	N
COLVILLE RIVER	ADL389114	ALASKA	CPAI	78.0000000	APC	22.0000000					10/31/2005	363.06	12.500	N	N
COLVILLE RIVER	ADL389115	ALASKA	CPAI	78.0000000	APC	22.0000000					10/31/2005	640.00	12.500	N	N
COLVILLE RIVER	ADL389116	ALASKA	CPAI	78.0000000	APC	22.0000000					10/31/2005	537.13	12.500	N	N
COLVILLE RIVER	ADL389725	ALASKA	CPAI	55.6200000	PAAI	22.0000000	APC	22.0000000	PETRO-HUNT	.3800000	10/31/2003	1249.00	16.667	N	N
COLVILLE RIVER	ADL389726	ALASKA	CPAI	56.0000000	PAAI	22.0000000	APC	22.0000000			12/31/2004	138.00	16.667	N	N

UNIT	AGENCY LEASE NO	LESSOR	NOTIFICATION LESSEE NAME	NOTIFICATION LESSEE WI	OTHER WIO NAME	OTHER WIO WI	OTHER WIO NAME	OTHER WIO WI	OTHER WIO NAME	OTHER WIO WI	EXPIRATION	ACRES	ROYALTY	NET PROFIT	SLIDING
DUCK ISLAND	ADL034633	ALASKA	BPXA	100.0000000							03/31/1977	2560.00	12.500	N	N
DUCK ISLAND	ADL034634	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	03/31/1977	2560.00	12.500	N	N
DUCK ISLAND	ADL034636	ALASKA	BPXA	100.0000000							03/27/1984	2560.00	12.500	N	N
DUCK ISLAND	ADL047502	ALASKA	UNOCAL	25.0000000	EM AK	50.0000000	BPXA	25.0000000			09/30/1979	2469.00	12.500	N	N
DUCK ISLAND	ADL047503	ALASKA	EM AK (1)	50.0000000	UNOCAL	25.0000000	BPXA	25.0000000			09/30/1979	2560.00	12.500	N	N
DUCK ISLAND	ADL047504	ALASKA	EM AK (1)	100.0000000							09/30/1979	2560.00	12.500	N	N
DUCK ISLAND	ADL047505	ALASKA	EM AK (1)	100.0000000							09/30/1979	2560.00	12.500	N	N
DUCK ISLAND	ADL047506	ALASKA	UNOCAL	50.0000000	BPXA	50.0000000					09/30/1979	2480.00	12.500	N	N
DUCK ISLAND	ADL312828	ALASKA	BPXA	98.0000000	NANA	1.5000000	DOYON	0.5000000			01/31/1990	4299.74	20.000	80.000	N
DUCK ISLAND	ADL312834	ALASKA	EM AK (1)	33.3333400	CPAI	33.3333300	UNOCAL	33.3333300			01/31/1990	3580.64	20.000	49.000	N

UNIT	AGENCY LEASE NO	LESSOR	NOTIFICATION LESSEE NAME	NOTIFICATION LESSEE WI	OTHER WIO NAME	OTHER WIO WI	OTHER WIO NAME	OTHER WIO WI	OTHER WIO NAME	OTHER WIO WI	EXPIRATION	ACRES	ROYALTY	NET PROFIT	SLIDING
KUPARUK RIVER	ADL025512	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	01/29/2001	2544.00	12.500	N	N
KUPARUK RIVER	ADL025513	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	01/29/2001	2560.00	12.500	N	N
KUPARUK RIVER	ADL025519	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	01/29/2001	2560.00	12.500	N	N
KUPARUK RIVER	ADL025520	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	01/29/2001	2560.00	12.500	N	N
KUPARUK RIVER	ADL025521	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	01/29/2001	2555.00	12.500	N	N
KUPARUK RIVER	ADL025522	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	03/27/1984	2560.00	12.500	N	N
KUPARUK RIVER	ADL025523	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	03/27/1984	2560.00	12.500	N	N
KUPARUK RIVER	ADL025524	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	03/27/1984	1920.00	12.500	N	N
KUPARUK RIVER	ADL025528	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	06/01/2005	2560.00	12.500	N	N
KUPARUK RIVER	ADL025531	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	03/27/1984	2560.00	12.500	N	N
KUPARUK RIVER	ADL025532	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	03/27/1984	2560.00	12.500	N	N
KUPARUK RIVER	ADL025543	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	06/01/2005	1280.00	12.500	N	N
KUPARUK RIVER	ADL025544	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	06/01/2005	2560.00	12.500	N	N
KUPARUK RIVER	ADL025546	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	03/27/1984	2560.00	12.500	N	N
KUPARUK RIVER	ADL025547	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	03/27/1984	2560.00	12.500	N	N
KUPARUK RIVER	ADL025548	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	03/27/1984	2560.00	12.500	N	N
KUPARUK RIVER	ADL025549	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	03/27/1984	2560.00	12.500	N	N
KUPARUK RIVER	ADL025551	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	06/01/2005	2560.00	12.500	N	N
KUPARUK RIVER	ADL025552	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	06/01/2005	2560.00	12.500	N	N
KUPARUK RIVER	ADL025553	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	06/01/2005	1228.00	12.500	N	N
KUPARUK RIVER	ADL025568	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	03/27/1984	2560.00	12.500	N	N
KUPARUK RIVER	ADL025569	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	03/27/1984	2560.00	12.500	N	N
KUPARUK RIVER	ADL025570	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	03/27/1984	2560.00	12.500	N	N
KUPARUK RIVER	ADL025571	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	03/27/1984	2560.00	12.500	N	N
KUPARUK RIVER	ADL025585	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	03/27/1984	2491.00	12.500	N	N
KUPARUK RIVER	ADL025586	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	03/27/1984	2560.00	12.500	N	N
KUPARUK RIVER	ADL025587	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	03/27/1984	2560.00	12.500	N	N
KUPARUK RIVER	ADL025588	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	03/27/1984	2560.00	12.500	N	N
KUPARUK RIVER	ADL025589	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	03/27/1984	2560.00	12.500	N	N
KUPARUK RIVER	ADL025590	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	03/27/1984	2501.00	12.500	N	N
KUPARUK RIVER	ADL025603	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	03/27/1984	2512.00	12.500	N	N
KUPARUK RIVER	ADL025604	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	03/27/1984	2560.00	12.500	N	N
KUPARUK RIVER	ADL025605	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	03/27/1984	2560.00	12.500	N	N
KUPARUK RIVER	ADL025607	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	03/27/1984	2560.00	12.500	N	N
KUPARUK RIVER	ADL025608	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	03/27/1984	2523.00	12.500	N	N
KUPARUK RIVER	ADL025627	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	03/27/1984	2560.00	12.500	N	N
KUPARUK RIVER	ADL025628	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	03/27/1984	2437.00	12.500	N	N
KUPARUK RIVER	ADL025629	ALASKA	CPAI	55.2937640	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	03/27/1984	2560.00	12.500	N	N
KUPARUK RIVER	ADL025630	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	03/27/1984	2560.00	12.500	N	N
KUPARUK RIVER	ADL025631	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	03/27/1984	2437.00	12.500	N	N
KUPARUK RIVER	ADL025632	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	03/27/1984	2448.00	12.500	N	N
KUPARUK RIVER	ADL025633	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	03/27/1984	2560.00	12.500	N	N
KUPARUK RIVER	ADL025634	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	03/27/1984	2560.00	12.500	N	N
KUPARUK RIVER	ADL025635	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	03/27/1984	2448.00	12.500	N	N
KUPARUK RIVER	ADL025636	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	03/27/1984	2560.00	12.500	N	N
KUPARUK RIVER	ADL025638	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	03/27/1984	2560.00	12.500	N	N
KUPARUK RIVER	ADL025639	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	03/27/1984	2560.00	12.500	N	N
KUPARUK RIVER	ADL025640	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	03/27/1984	2459.00	12.500	N	N
KUPARUK RIVER	ADL025641	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	03/27/1984	2560.00	12.500	N	N
KUPARUK RIVER	ADL025642	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	03/27/1984	2560.00	12.500	N	N
KUPARUK RIVER	ADL025643	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	03/27/1984	2459.00	12.500	N	N
KUPARUK RIVER	ADL025644	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	03/27/1984	2469.00	12.500	N	N
KUPARUK RIVER	ADL025645	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	03/27/1984	2560.00	12.500	N	N

	AGENCY		NOTIFICATION LESSEE		OTHER WIO		OTHER WIO		OTHER WIO					NET	
UNIT	LEASE NO	LESSOR	NAME	WI	NAME	WI	NAME	WI	NAME	WI	EXPIRATION	ACRES	ROYALTY	PROFIT	SLIDING
KUPARUK RIVER	ADL025646	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	03/27/1984	2560.00	12.500	N	N
KUPARUK RIVER	ADL025647	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	03/27/1984	2469.00	12.500	N	N
KUPARUK RIVER	ADL025648	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	03/27/1984	2560.00	12.500	N	N
KUPARUK RIVER	ADL025649	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	03/27/1984	2560.00	12.500	N	N
KUPARUK RIVER	ADL025650	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	03/27/1984	2560.00	12.500	N	N
KUPARUK RIVER	ADL025651	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	03/27/1984	2560.00	12.500	N	N
KUPARUK RIVER	ADL025652	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	03/27/1984	2480.00	12.500	N	N
KUPARUK RIVER	ADL025653	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	03/27/1984	2560.00	12.500	N	N
KUPARUK RIVER	ADL025654	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	03/27/1984	2560.00	12.500	N	N
KUPARUK RIVER	ADL025655	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	03/27/1984	2480.00	12.500	N	N
KUPARUK RIVER	ADL025656	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	03/27/1984	2491.00	12.500	N	N
KUPARUK RIVER	ADL025657	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	03/27/1984	2560.00	12.500	N	N
KUPARUK RIVER	ADL025658	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	03/27/1984	2560.00	12.500	N	N
KUPARUK RIVER	ADL025659	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	03/27/1984	2491.00	12.500	N	N
KUPARUK RIVER	ADL025660	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	03/27/1984	2560.00	12.500	N	N
KUPARUK RIVER	ADL025661	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	03/27/1984	2560.00	12.500	N	N
KUPARUK RIVER	ADL025662	ALASKA	CPAI	26.0613170	EM AK	50.3648000	BPXA	18.5146830	UNOCAL, et al	5.0592000	03/27/1984	2560.00	12.500	N	N
KUPARUK RIVER	ADL025663	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	03/27/1984	2560.00	12.500	N	N
KUPARUK RIVER	ADL025664	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	03/27/1984	2501.00	12.500	N	N
KUPARUK RIVER	ADL025665	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	03/27/1984	2560.00	12.500	N	N
KUPARUK RIVER	ADL025666	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	03/27/1984	2560.00	12.500	N	N
KUPARUK RIVER	ADL025667	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	03/27/1984	2501.00	12.500	N	N
KUPARUK RIVER	ADL025668	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	03/27/1984	2512.00	12.500	N	N
KUPARUK RIVER	ADL025670	ALASKA	CPAI	26.0613170	EM AK	50.3648000	BPXA	18.5146830	UNOCAL, et al	5.0592000	03/27/1984	2560.00	12.500	N	N
KUPARUK RIVER	ADL025671	ALASKA	CPAI	26.0613170	EM AK	50.3648000	BPXA	18.5146830	UNOCAL, et al	5.0592000	03/27/1984	2512.00	12.500	N	N
KUPARUK RIVER	ADL028242	ALASKA	CPAI	26.0613170	EM AK	50.3648000	BPXA	18.5146830	UNOCAL, et al	5.0592000	03/27/1984	2469.00	12.500	N	N
KUPARUK RIVER	ADL028243	ALASKA	EM AK (2)	0.3648000	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	03/27/1984	2480.00	12.500	N	N
KUPARUK RIVER	ADL028248	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	03/27/1984	1851.00	12.500	N	N
KUPARUK RIVER	ADL355023	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL. et al	5.0592000	EM AK	0.3648000	05/31/1993	3255.00	12.500	30.000	N
KUPARUK RIVER	ADL355024	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL. et al	5.0592000	EM AK	0.3648000	05/31/1993	5580.00	12.500	30.000	N
KUPARUK RIVER	ADL355030	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL. et al	5.0592000	EM AK	0.3648000	06/30/1993	4480.00	12.500	30.000	N
KUPARUK RIVER	ADL355032	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL. et al	5.0592000	EM AK	0.3648000	06/30/1993	5108.00	12.500	30.000	N
KUPARUK RIVER	ADL365501	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL. et al	5.0592000	EM AK	0.3648000	11/30/1995	640.00	16.667	N	N
KUPARUK RIVER	ADL373111	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL. et al	5.0592000	EM AK	0.3648000	09/01/2003	5760.00	12.500	N	N
KUPARUK RIVER	ADL373112	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL. et al	5.0592000	EM AK	0.3648000	11/30/1998	5583.00	12.500	N	N
KUPARUK RIVER	ADL373301	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL. et al	5.0592000	EM AK	0.3648000	02/28/1999	677.15	12.500	N	N
KUPARUK RIVER	ADL375073	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL. et al	5.0592000	EM AK	0.3648000	09/01/2003	2560.00	12.500	N	N
KUPARUK RIVER	ADL375074	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL. et al	5.0592000	EM AK	0.3648000	09/01/2003	2560.00	12.500	N	N
KUPARUK RIVER	ADL375075	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL. et al	5.0592000	EM AK	0.3648000	03/31/2001	2533.00	12.500	N	N
KUPARUK RIVER	ADL375077	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL. et al	5.0592000	EM AK	0.3648000	09/01/2003	2560.00	12.500	N	N
KUPARUK RIVER	ADL375078	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL. et al	5.0592000	EM AK	0.3648000	09/01/2003	2560.00	12.500	N	N
KUPARUK RIVER	ADL375079	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL. et al	5.0592000	EM AK	0.3648000	09/01/2003	2560.00	12.500	N	N
KUPARUK RIVER	ADL375080	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL. et al	5.0592000	EM AK	0.3648000	09/01/2003	2560.00	12.500	N	N
KUPARUK RIVER	ADL375107	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL. et al	5.0592000	EM AK	0.3648000	01/31/2003	1280.00	12.500	N	N
KUPARUK RIVER	ADL375108	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL. et al	5.0592000	EM AK	0.3648000	03/31/2001	2523.00	12.500	N	N
KUPARUK RIVER	ADL380049	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	09/28/2003	2560.00	12.500	N	N
KUPARUK RIVER	ADL380050	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	09/28/2003	2560.00	12.500	N	N
KUPARUK RIVER	ADL380051	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL. et al	5.0592000	EM AK	0.3648000	01/31/2003	2560.00	12.500	N	N
KUPARUK RIVER	ADL380052	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL. et al	5.0592000	EM AK	0.3648000	01/31/2003	2560.00	12.500	N	N
KUPARUK RIVER	ADL380053	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL. et al	5.0592000	EM AK	0.3648000	01/31/2003	2560.00	12.500	N	N
KUPARUK RIVER	ADL380054	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL. et al	5.0592000	EM AK	0.3648000	01/31/2003	2560.00	12.500	N	N
KUPARUK RIVER	ADL380055	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL. et al	5.0592000	EM AK	0.3648000	06/01/2007	2560.00	12.500	N	N
KUPARUK RIVER	ADL380058	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL. et al	5.0592000	EM AK	0.3648000	01/31/2003	2560.00	12.500	N	N

	AGENCY		NOTIFICATION LESSEE		OTHER WIO		OTHER WIO		OTHER WIO					NET	
UNIT	LEASE NO	LESSOR	NAME	WI	NAME	WI	NAME	WI	NAME	WI	EXPIRATION	ACRES	ROYALTY	PROFIT	SLIDING
KUPARUK RIVER	ADL380062	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL. et al	5.0592000	EM AK	0.3648000	06/01/2007	2512.00	12.500	N	N
KUPARUK RIVER	ADL380091	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL. et al	5.0592000	EM AK	0.3648000	06/01/2007	640.00	12.500	N	N
KUPARUK RIVER	ADL380106	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL. et al	5.0592000	EM AK	0.3648000	06/01/2005	2437.00	12.500	N	N
KUPARUK RIVER	ADL380107	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL. et al	5.0592000	EM AK	0.3648000	06/01/2005	2448.00	12.500	N	N
KUPARUK RIVER	ADL385168	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL. et al	5.0592000	EM AK	0.3648000	06/01/2005	2560.00	12.500	N	N
KUPARUK RIVER	ADL385170	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL. et al	5.0592000	EM AK	0.3648000	06/01/2005	2560.00	12.500	N	N
KUPARUK RIVER	ADL385171	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL. et al	5.0592000	EM AK	0.3648000	06/01/2005	2523.00	12.500	N	N
KUPARUK RIVER	ADL385172	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL. et al	5.0592000	EM AK	0.3648000	06/01/2007	2560.00	12.500	N	N
KUPARUK RIVER	ADL385175	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL. et al	5.0592000	EM AK	0.3648000	06/01/2007	2501.00	12.500	N	N
KUPARUK RIVER	ADL385189	ALASKA	BPXA	100.0000000							06/01/2007	2560.00	12.500	N	N
KUPARUK RIVER	ADL389058	ALASKA	CPAI	55.5070500	BPXA	39.4337500	UNOCAL	4.9506000	CHEVRON	0.1086000	10/31/2005	5607.00	12.500	N	N
KUPARUK RIVER	ADL389059	ALASKA	CPAI	55.5070500	BPXA	39.4337500	UNOCAL	4.9506000	CHEVRON	0.1086000	10/31/2005	5760.00	12.500	N	N
KUPARUK RIVER	ADL389132	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	11/30/2005	1280.00	12.500	N	N
KUPARUK RIVER	ADL389133	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	11/30/2005	2469.00	12.500	N	N
KUPARUK RIVER	ADL390057	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	08/31/2009	1280.00	16.670	N	N
KUPARUK RIVER	ADL390303	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	06/01/2005	1280.00	12.500	N	N
KUPARUK RIVER	ADL390305	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	06/01/2005	1231.00	12.500	N	N

UNIT	AGENCY LEASE NO	LESSOR	NOTIFICATION LESSEE NAME	NOTIFICATION LESSEE WI	OTHER WIO NAME	OTHER WIO WI	OTHER WIO NAME	OTHER WIO WI	OTHER WIO NAME	OTHER WIO WI	EXPIRATION	ACRES	ROYALTY	NET PROFIT	SLIDING
MILNE POINT	ADL025509	ALASKA	BPXA	91.1900000	BPAP	8.8100000					01/28/2001	2533.00	12.500	N	N
MILNE POINT	ADL025514	ALASKA	BPXA	91.1900000	BPAP	8.8100000					01/29/2001	2560.00	12.500	N	N
MILNE POINT	ADL025515	ALASKA	BPXA	91.1900000	BPAP	8.8100000					01/29/2001	2544.00	12.500	N	N
MILNE POINT	ADL025516	ALASKA	BPXA	91.1900000	BPAP	8.8100000					01/29/2001	1280.00	12.500	N	N
MILNE POINT	ADL025517	ALASKA	BPXA	91.1900000	BPAP	8.8100000					01/29/2001	2555.00	12.500	N	N
MILNE POINT	ADL025518	ALASKA	BPXA	91.1900000	BPAP	8.8100000					01/29/2001	2560.00	12.500	N	N
MILNE POINT	ADL025906	ALASKA	BPXA	91.1900000	BPAP	8.8100000					01/29/2001	2560.00	12.500	N	N
MILNE POINT	ADL028231	ALASKA	BPXA	91.1900000	BPAP	8.8100000					01/29/2001	2555.00	12.500	N	N
MILNE POINT	ADL028232	ALASKA	BPXA	91.1900000	BPAP	8.8100000					01/29/2001	2560.00	12.500	N	N
MILNE POINT	ADL047432	ALASKA	BPXA	91.1900000	BPAP	8.8100000					10/30/1979	1268.00	20.000	N	N
MILNE POINT	ADL047433	ALASKA	BPXA	91.1900000	BPAP	8.8100000					10/30/1979	2560.00	20.000	N	N
MILNE POINT	ADL047434	ALASKA	BPXA	91.1900000	BPAP	8.8100000					10/30/1979	2560.00	20.000	N	N
MILNE POINT	ADL047437	ALASKA	BPXA	91.1900000	BPAP	8.8100000					10/30/1979	2560.00	20.000	N	N
MILNE POINT	ADL047438	ALASKA	BPXA	91.1900000	BPAP	8.8100000					10/30/1979	2544.00	20.000	N	N
MILNE POINT	ADL315848	ALASKA	BPXA	91.1900000	BPAP	8.8100000					01/29/2001	1280.00	12.500	N	N
MILNE POINT	ADL355016	ALASKA	BPXA	91.1900000	BPAP	8.8100000					07/31/1993	5071.00	12.500	40.000	N
MILNE POINT	ADL355017	ALASKA	BPXA	91.1900000	BPAP	8.8100000					07/31/1993	4480.00	12.500	40.000	N
MILNE POINT	ADL355018	ALASKA	BPXA	91.1900000	BPAP	8.8100000					07/31/1993	5083.00	12.500	30.000	N
MILNE POINT	ADL355021	ALASKA	BPXA	91.1900000	BPAP	8.8100000					07/31/1993	5120.00	12.500	30.000	N
MILNE POINT	ADL375132	ALASKA	BPXA	91.1900000	BPAP	8.8100000					03/31/2001	2560.00	12.500	N	N
MILNE POINT	ADL375133	ALASKA	BPXA	91.1900000	BPAP	8.8100000					03/31/2001	2560.00	12.500	N	N
MILNE POINT	ADL380109	ALASKA	BPXA	91.1900000	BPAP	8.8100000					01/31/2003	2560.00	12.500	N	N
MILNE POINT	ADL380110	ALASKA	BPXA	91.1900000	BPAP	8.8100000					01/31/2003	2437.00	12.500	N	N
MILNE POINT	ADL388235	ALASKA	BPXA	91.1900000	BPAP	8.8100000					05/31/1993	1920.00	12.500	30.000	N

UNIT	AGENCY LEASE NO	LESSOR	NOTIFICATION LESSEE NAME	NOTIFICATION LESSEE WI	OTHER WIO NAME	OTHER WIO WI	OTHER WIO NAME	OTHER WIO WI	OTHER WIO NAME	OTHER WIO WI	EXPIRATION	ACRES	ROYALTY	NET PROFIT	SLIDING
NORTHSTAR	ADL312798	ALASKA	BPXA	100.0000000							01/31/1990	4392.82	20.000	N	28.000
NORTHSTAR	ADL312799	ALASKA	BPXA	100.0000000							01/31/1990	4472.37	20.000	N	28.000
NORTHSTAR	ADL312808	ALASKA	BPXA	100.0000000							01/31/1990	3432.92	20.000	N	28.000
NORTHSTAR	ADL312809	ALASKA	BPXA	100.0000000							01/31/1990	5301.38	20.000	N	28.000
NORTHSTAR	ADL355001	ALASKA	BPXA	100.0000000							07/31/1993	5744.00	20.000	N	28.000
NORTHSTAR	Y00179	MMS	BPXA	100.0000000							11/05/2002	2251.99		N	N
NORTHSTAR	Y00181	MMS	BPXA	90.0000000	MURPHY AK	10.0000000					11/05/2002	5242.65		N	N
NORTHSTAR	Y01645	MMS	BPXA	100.0000000							11/30/2006	2929.64	12.500	N	N

UNIT	AGENCY LEASE NO	LESSOR	NOTIFICATION LESSEE NAME	NOTIFICATION LESSEE WI	OTHER WIO NAME	OTHER WIO WI	OTHER WIO NAME	OTHER WIO WI	OTHER WIO NAME	OTHER WIO WI	EXPIRATION	ACRES	ROYALTY	NET PROFIT	SLIDING
PT THOMSON	ADL028380	ALASKA	EM OIL	50.0000000	BPXA	50.0000000					03/27/1984	2544.00	12.500	N	N
PT THOMSON	ADL028381	ALASKA	EM	50.0000000	BPXA	28.0000000	CHEVRON	22.0000000			03/27/1984	2560.00	12.500	N	N
PT THOMSON	ADL028382	ALASKA	EM	50.0000000	BPXA	28.0000000	CHEVRON	22.0000000			03/27/1984	2560.00	12.500	N	N
PT THOMSON	ADL028383	ALASKA	EM	50.0000000	BPXA	28.0000000	CHEVRON	22.0000000			03/27/1984	2560.00	12.500	N	N
PT THOMSON	ADL028384	ALASKA	EM OIL	54.0464100	BPXA	29.9997220	EM	12.6742800	CHEVRON. et al	3.2795880	03/27/1984	1760.00	12.500	N	N
PT THOMSON	ADL028385	ALASKA	EM OIL	54.0464100	BPXA	29.9997220	EM	12.6742800	CHEVRON. et al	3.2795880	03/27/1984	637.00	12.500	N	N
PT THOMSON	ADL047556	ALASKA	EM	100.0000000							09/30/1979	2560.00	12.500	N	N
PT THOMSON	ADL047557	ALASKA	EM OIL	50.0000000	BPXA	50.0000000					09/30/1979	2523.00	12.500	N	N
PT THOMSON	ADL047558	ALASKA	EM OIL	50.0000000	BPXA	50.0000000					09/30/1979	2560.00	12.500	N	N
PT THOMSON	ADL047559	ALASKA	EM	100.0000000							09/30/1979	2560.00	12.500	N	N
PT THOMSON	ADL047560	ALASKA	EM	50.0000000	CPAI	20.1951200	LEEDE ED, et al	29.8048800			03/31/1980	640.00	12.500	N	N
PT THOMSON	ADL047561	ALASKA	EM	75.0000000	BPXA	14.0000000	CHEVRON	11.0000000			09/30/1979	2560.00	12.500	N	N
PT THOMSON	ADL047562	ALASKA	DEVON	10.0000000	EM	71.5315773	EM OIL	9.5000000	FOREST, et al	8.9684227	09/30/1979	2560.00	12.500	N	N
PT THOMSON	ADL047563	ALASKA	EM OIL	25.0000000	EM	50.0000000	BPXA	25.0000000			09/30/1979	2523.00	12.500	N	N
PT THOMSON	ADL047564	ALASKA	EM OIL	25.0000000	EM	50.0000000	BPXA	25.0000000			09/30/1979	2560.00	12.500	N	N
PT THOMSON	ADL047566	ALASKA	EM OIL	25.0000000	EM	50.0000000	BPXA	25.0000000			09/30/1979	2533.00	12.500	N	N
PT THOMSON	ADL047567	ALASKA	DEVON	10.0000000	EM	71.5315773	EM OIL	9.5000000	FOREST, et al	8.9684227	09/30/1979	2560.00	12.500	N	N
PT THOMSON	ADL047568	ALASKA	CHEVRON	44.0000000	BPXA	56.0000000					09/30/1979	2560.00	12.500	N	N
PT THOMSON	ADL047569	ALASKA	CHEVRON	22.0000000	EM	50.0000000	BPXA	28.0000000			09/30/1979	2533.00	12.500	N	N
PT THOMSON	ADL047570	ALASKA	CHEVRON	22.0000000	EM	50.0000000	BPXA	28.0000000			09/30/1979	2560.00	12.500	N	N
PT THOMSON	ADL047571	ALASKA	CHEVRON	44.0000000	BPXA	56.0000000					09/30/1979	2560.00	12.500	N	N
PT THOMSON	ADL047572	ALASKA	CHEVRON	17.6000000	BPXA	52.4000000	EM OIL	30.0000000			09/30/1979	2533.00	12.500	N	N
PT THOMSON	ADL047573	ALASKA	EM OIL	50.0000000	BPXA	50.0000000					09/30/1979	2544.00	12.500	N	N
PT THOMSON	ADL050983	ALASKA	EM	66.6700000	BPXA	33.3300000					03/31/1980	640.00	12.500	N	N
PT THOMSON	ADL051667	ALASKA	EM OIL	16.6670000	BPXA	25.9997400	EM	50.0000000	CHEVRON	7.3332600	03/31/1980	1243.00	12.500	N	N
PT THOMSON	ADL312862	ALASKA	EM	100.0000000							01/31/1990	5648.68	20.000	N	65.000
PT THOMSON	ADL312866	ALASKA	EM	100.0000000							01/31/1990	4935.47	20.000	52.000	
PT THOMSON	ADL343109	ALASKA	EM	50.0000000	BPXA	28.0000000	CHEVRON	22.0000000			07/31/1992	1970.16	12.500	40.000	N
PT THOMSON	ADL343110	ALASKA	BPXA	50.0000000	EM OIL	50.0000000					07/31/1992	1920.00	12.500	40.000	N
PT THOMSON	ADL343111	ALASKA	BPXA	56.0000000	CHEVRON	44.0000000					07/31/1992	2400.00	12.500	40.000	N
PT THOMSON	ADL343112	ALASKA	CHEVRON	44.0000000	BPXA	56.0000000					07/31/1992	3446.00	12.500	40.000	N
PT THOMSON	ADL372256	ALASKA	EM	100.0000000							11/30/1998	1412.00	20.000	N	N
PT THOMSON	ADL375064	ALASKA	CHEVRON	44.0000000	BPXA	56.0000000					03/31/2001	1062.00	16.667	N	N
PT THOMSON	ADL377015	ALASKA	BPXA	56.0000000	CHEVRON	44.0000000					07/31/2001	3554.30	20.000	N	N
PT THOMSON	ADL377016	ALASKA	CPAI	50.0000000	BPXA	50.0000000					07/31/2001	2779.16	20.000	N	N
PT THOMSON	ADL377017	ALASKA	EM	66.6667000	BPXA	18.6666480	CHEVRON	14.6666520			07/31/2001	5696.18	20.000	N	N
PT THOMSON	ADL377020	ALASKA	EM	66.6667000	BPXA	18.6666480	CHEVRON	14.6666520			07/31/2001	1909.74	20.000	N	N
PT THOMSON	ADL382101	ALASKA	CHEVRON	44.0000000	BPXA	56.0000000					06/30/2003	1280.00	12.500	N	N
PT THOMSON	ADL388425	ALASKA	BPXA	56.0000000	CHEVRON	44.0000000					12/31/2004	1162.08	20.000	N	N
PT THOMSON	ADL388426	ALASKA	BPXA	56.0000000	CHEVRON	44.0000000					12/31/2004	821.74	20.000	N	N
PT THOMSON	ADL389716	ALASKA	EM	100.0000000							05/31/2008	1473.92	16.667	N	N
PT THOMSON	ADL389727	ALASKA	BPXA	56.0000000	CHEVRON	44.0000000					07/31/2001	2143.39	20.000	N	N
PT THOMSON	ADL389728	ALASKA	CPAI	50.0000000	BPXA	50.0000000					07/31/2001	2952.62	20.000	N	N
PT THOMSON	ADL389730	ALASKA	EM	66.6667000	BPXA	18.6666480	CHEVRON	14.6666520			07/31/2001	3684.31	20.000	N	N
PT THOMSON	ADL390310	ALASKA	EM	37.2750000	BPXA	32.3260000	CHEVRON	25.3990000	CPAI	5.0000000	03/31/2010	15.80	20.000	N	N

	AGENCY		NOTIFICATION LESSEE		OTHER WIO		OTHER WIO		OTHER WIO					NET	
UNIT	LEASE NO	LESSOR	NAME	WI	NAME	WI	NAME	WI	NAME	WI	EXPIRATION	ACRES	ROYALTY	PROFIT	SLIDING
PRUDHOE BAY	ADL025637	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	03/27/1984	2560.00	12.500	N	N
PRUDHOE BAY	ADL028238	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	03/27/1984	2560.00	12.500	N	N
PRUDHOE BAY	ADL028239	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	03/27/1984	2560.00	12.500	N	N
PRUDHOE BAY	ADL028240	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	03/27/1984	2560.00	12.500	N	N
PRUDHOE BAY	ADL028241	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	03/27/1984	2560.00	12.500	N	N
PRUDHOE BAY	ADL028244	ALASKA	BPXA	18.5146830	EM AK	50.3648000	CPAI	26.0613170	UNOCAL, et al	5.0592000	03/27/1984	2560.00	12.500	N	N
PRUDHOE BAY	ADL028245	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	03/27/1984	2560.00	12.500	N	N
PRUDHOE BAY	ADL028246	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	03/27/1984	2560.00	12.500	N	N
PRUDHOE BAY	ADL028255	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	09/30/2002	2448.00	12.500	N	N
PRUDHOE BAY	ADL028256	ALASKA	BPXA	50.0000000	CPAI	25.0000000	EM AK	25.0000000			09/30/2002	2560.00	12.500	N	N
PRUDHOE BAY	ADL028257	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	09/30/2002	2560.00	12.500	N	N
PRUDHOE BAY	ADL028258	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	09/30/2002	2560.00	12.500	N	N
PRUDHOE BAY	ADL028259	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	09/30/2002	2459.00	12.500	N	N
PRUDHOE BAY	ADL028260	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	03/27/1984	2560.00	12.500	N	N
PRUDHOE BAY	ADL028261	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	03/27/1984	2560.00	12.500	N	N
PRUDHOE BAY	ADL028262	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	03/27/1984	2480.00	12.500	N	N
PRUDHOE BAY	ADL028263	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	03/27/1984	2560.00	12.500	N	N
PRUDHOE BAY	ADL028264	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	03/27/1984	2560.00	12.500	N	N
PRUDHOE BAY	ADL028265	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	03/27/1984	2560.00	12.500	N	N
PRUDHOE BAY	ADL028275	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	03/27/1984	1280.00	12.500	N	N
PRUDHOE BAY	ADL028276	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	03/27/1984	640.00	12.500	N	N
PRUDHOE BAY	ADL028277	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	03/27/1984	2560.00	12.500	N	N
PRUDHOE BAY	ADL028278	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	03/27/1984	2560.00	12.500	N	N
PRUDHOE BAY	ADL028279	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	03/27/1984	2459.00	12.500	N	N
PRUDHOE BAY	ADL028280	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	03/27/1984	2560.00	12.500	N	N
PRUDHOE BAY	ADL028281	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	03/27/1984	2560.00	12.500	N	N
PRUDHOE BAY	ADL028282	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	03/27/1984	2469.00	12.500	N	N
PRUDHOE BAY	ADL028283	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	03/27/1984	2480.00	12.500	N	N
PRUDHOE BAY	ADL028284	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	03/27/1984	2560.00	12.500	N	N
PRUDHOE BAY	ADL028285	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	03/27/1984	2560.00	12.500	N	N
PRUDHOE BAY	ADL028286	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	03/27/1984	2560.00	12.500	N	N
PRUDHOE BAY	ADL028287	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	03/27/1984	2560.00	12.500	N	N
PRUDHOE BAY	ADL028288	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	03/27/1984	2491.00	12.500	N	N
PRUDHOE BAY	ADL028289	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	03/27/1984	2501.00	12.500	N	N
PRUDHOE BAY	ADL028290	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	03/27/1984	2560.00	12.500	N	N
PRUDHOE BAY	ADL028297	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	09/30/2002	2560.00	12.500	N	N
PRUDHOE BAY	ADL028298	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	09/30/2002	312.00	12.500	N	N
PRUDHOE BAY	ADL028299	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	09/30/2002	2459.00	12.500	N	N
PRUDHOE BAY	ADL028300	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	09/30/2002	2560.00	12.500	N	N
PRUDHOE BAY	ADL028301	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	09/30/2002	2560.00	12.500	N	N
PRUDHOE BAY	ADL028302	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	03/27/1984	2560.00	12.500	N	N
PRUDHOE BAY	ADL028303	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	03/27/1984	2560.00	12.500	N	N
PRUDHOE BAY	ADL028304	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	03/27/1984	2469.00	12.500	N	N
PRUDHOE BAY	ADL028305	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	03/27/1984	2480.00	12.500	N	N
PRUDHOE BAY	ADL028306	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	03/27/1984	2560.00	12.500	N	N
PRUDHOE BAY	ADL028307	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	03/27/1984	2560.00	12.500	N	N
PRUDHOE BAY	ADL028308	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	03/27/1984	2560.00	12.500	N	N
PRUDHOE BAY	ADL028309	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	03/27/1984	2560.00	12.500	N	N
PRUDHOE BAY	ADL028310	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	03/27/1984	2491.00	12.500	N	N
PRUDHOE BAY	ADL028311	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	03/27/1984	2560.00	12.500	N	N
PRUDHOE BAY	ADL028312	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	03/27/1984	2560.00	12.500	N	N
PRUDHOE BAY	ADL028313	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	03/27/1984	2501.00	12.500	N	N
PRUDHOE BAY	ADL028314	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	03/27/1984	2560.00	12.500	N	N

	AGENCY		NOTIFICATION LESSEE		OTHER WIO		OTHER WIO		OTHER WIO					NET	
UNIT	LEASE NO	LESSOR	NAME	WI	NAME	WI	NAME	WI	NAME	WI	EXPIRATION	ACRES	ROYALTY	PROFIT	SLIDING
PRUDHOE BAY	ADL028315	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	03/27/1984	2560.00	12.500	N	N
PRUDHOE BAY	ADL028316	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	03/27/1984	2560.00	12.500	N	N
PRUDHOE BAY	ADL028320	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	03/27/1984	2560.00	12.500	N	N
PRUDHOE BAY	ADL028321	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	03/27/1984	2480.00	12.500	N	N
PRUDHOE BAY	ADL028322	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	03/27/1984	2560.00	12.500	N	N
PRUDHOE BAY	ADL028323	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	03/27/1984	2560.00	12.500	N	N
PRUDHOE BAY	ADL028324	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	03/27/1984	2560.00	12.500	N	N
PRUDHOE BAY	ADL028325	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	03/27/1984	2560.00	12.500	N	N
PRUDHOE BAY	ADL028326	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	03/27/1984	2491.00	12.500	N	N
PRUDHOE BAY	ADL028327	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	03/27/1984	2560.00	12.500	N	N
PRUDHOE BAY	ADL028328	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	03/27/1984	2560.00	12.500	N	N
PRUDHOE BAY	ADL028329	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	03/27/1984	2501.00	12.500	N	N
PRUDHOE BAY	ADL028330	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	03/27/1984	2512.00	12.500	N	N
PRUDHOE BAY	ADL028331	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	03/27/1984	2560.00	12.500	N	N
PRUDHOE BAY	ADL028332	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	03/27/1984	2560.00	12.500	N	N
PRUDHOE BAY	ADL028333	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	03/27/1984	2560.00	12.500	N	N
PRUDHOE BAY	ADL028334	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	03/27/1984	2560.00	12.500	N	N
PRUDHOE BAY	ADL028335	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	03/27/1984	2523.00	12.500	N	N
PRUDHOE BAY	ADL028337	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	03/27/1984	2560.00	12.500	N	N
PRUDHOE BAY	ADL028338	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	03/27/1984	2469.00	12.500	N	N
PRUDHOE BAY	ADL028339	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	03/27/1984	2480.00	12.500	N	N
PRUDHOE BAY	ADL028340	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	03/27/1984	2560.00	12.500	N	N
PRUDHOE BAY	ADL028342	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	03/27/1984	1280.00	12.500	N	N
PRUDHOE BAY	ADL028343	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	03/27/1984	2491.00	12.500	N	N
PRUDHOE BAY	ADL028344	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	03/27/1984	2560.00	12.500	N	N
PRUDHOE BAY	ADL028345	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	03/27/1984	2501.00	12.500	N	N
PRUDHOE BAY	ADL028346	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	03/27/1984	2512.00	12.500	N	N
PRUDHOE BAY	ADL028349	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	03/27/1984	2523.00	12.500	N	N
PRUDHOE BAY	ADL034622	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	12/08/2002	2560.00	12.500	N	N
PRUDHOE BAY	ADL034624	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	12/08/2002	2560.00	12.500	N	N
PRUDHOE BAY	ADL034625	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	03/31/1977	2560.00	12.500	N	N
PRUDHOE BAY	ADL034626	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	03/31/1977	2560.00	12.500	N	N
PRUDHOE BAY	ADL034627	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	03/31/1977	2448.00	12.500	N	N
PRUDHOE BAY	ADL034628	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	09/04/1996	2459.00	12.500	N	N
PRUDHOE BAY	ADL034629	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	09/04/1996	2560.00	12.500	N	N
PRUDHOE BAY	ADL034630	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	09/04/1996	2560.00	12.500	N	N
PRUDHOE BAY	ADL034631	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	03/27/1984	2560.00	12.500	N	N
PRUDHOE BAY	ADL034632	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	03/31/1977	2469.00	12.500	N	N
PRUDHOE BAY	ADL034635	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	03/27/1984	2459.00	12.500	N	N
PRUDHOE BAY	ADL047446	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	09/30/1979	2448.00	12.500	N	N
PRUDHOE BAY	ADL047447	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	09/30/1979	2560.00	12.500	N	N
PRUDHOE BAY	ADL047448	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	09/30/1979	2560.00	12.500	N	N
PRUDHOE BAY	ADL047449	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	09/30/1979	2459.00	12.500	N	N
PRUDHOE BAY	ADL047450	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	09/30/1979	2469.00	12.500	N	N
PRUDHOE BAY	ADL047451	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	09/30/1979	2560.00	12.500	N	N
PRUDHOE BAY	ADL047452	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	09/30/1979	2560.00	12.500	N	N
PRUDHOE BAY	ADL047453	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	09/30/1979	2491.00	12.500	N	N
PRUDHOE BAY	ADL047454	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	09/30/1979	2560.00	12.500	N	N
PRUDHOE BAY	ADL047469	ALASKA	EM AK (3)	50.0000000	CPAI	50.0000000					09/30/1979	2448.00	12.500	N	N
PRUDHOE BAY	ADL047471	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	09/30/1979	2560.00	12.500	N	N
PRUDHOE BAY	ADL047472	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	09/30/1979	2560.00	12.500	N	N
PRUDHOE BAY	ADL047475	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	09/30/1979	2512.00	12.500	N	N
PRUDHOE BAY	ADL047476	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	09/30/1979	2560.00	12.500	N	N

	AGENCY		NOTIFICATION LESSEE		OTHER WIO		OTHER WIO		OTHER WIO					NET	
UNIT	LEASE NO	LESSOR	NAME	WI	NAME	WI	NAME	WI	NAME	WI	EXPIRATION	ACRES	ROYALTY	PROFIT	SLIDING
PRUDHOE BAY	ADL080595	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	09/30/1979	1280.00	12.500	N	N
PRUDHOE BAY	ADL365548	ALASKA	BPXA	26.3553560	EM AK	36.3954910	CPAI	36.0693850	CHEVRON. et al	1.1797680	11/30/1995	3601.10	16.667	N	N

	AGENCY		NOTIFICATION LESSEE		OTHER WIO		OTHER WIO		OTHER WIO					NET	
UNIT	LEASE NO	LESSOR	NAME	WI	NAME	WI	NAME	WI	NAME	WI	EXPIRATION	ACRES	ROYALTY	PROFIT	SLIDING

LEGEND	
APC	ANADARKO PETROLEUM COMPANY
BPAP	BP AMERICA PRODUCTION COMPANY
BPXA	BP EXPLORATION (ALASKA) INC.
CHEVRON	CHEVRON U.S.A. INC.
CPAI	CONOCOPHILLIPS ALASKA, INC.
CPCO	CONOCOPHILLIPS COMPANY
DEVON	DEVON ENERGY PRODUCTION COMPANY, L.P.
DOYON	DOYON LIMITED
EM	EXXON MOBIL CORPORATION
EM AK	EXXONMOBIL ALASKA PRODUCTION INC.
EM OIL	EXXONMOBIL OIL CORPORATION
ENCANA	ENCANA OIL AND GAS (USA) INC.
FOREST	FOREST OIL CORPORATION
LEEDE, ED	EDWARD H. LEEDE
MURPHY	MURPHY EXPLORATION (ALASKA), INC.
MURPHY AK	MURPHY EXPLORATION (ALASKA), INC.
NANA	NANA REGIONAL CORPORATION INC.
PAAI	PHILLIPS ALPINE ALASKA L.L.C.
PETRO-HUNT	PETRO-HUNT L. L. C.
UNOCAL	UNION OIL COMPANY OF CALIFORNIA
ALASKA	State of Alaska, Department of Natural Resources, Division of Oil and Gas
ASRC	Artic Slope Regional Corporation
BLM	Bureau of Land Management
MMS	Minerals Management Service

(1) Lessee of Record is EXXONMOBIL CORPORATION
(2) Lessee of Record is EXXONMOBIL OIL CORPORATION
(3) Lessee of Record is BP EXPLORATION (ALASKA) INC.

NOTE: Where a lease has been divided into segments in the Department of Natural Resources records, the ownership shown above is for only one segment.

Appendix A.7	Description of Leases Outside Existing Units

Listing of North Slope Leases

DESCRIPTION OF LEASES OUTSIDE EXISTING UNITS (APPENDIX A.7)

Effective September 15, 2003

	AGENCY		NOTIFICATION LESSEE		OTHER WIO		OTHER WIO		OTHER WIO					NET	
UNIT	LEASE NO	LESSOR	NAME	WI	NAME	WI	NAME	WI	NAME	WI	EXPIRATION	ACRES	ROYALTY	PROFIT	SLIDING
N/A	AA081727	BLM	CPCO	59.0000000	CHEVRON	30.0000000	APC	11.0000000			8/31/2009	11378.88	12.500	N	N
N/A	AA081728	BLM	CPCO	59.0000000	CHEVRON	30.0000000	APC	11.0000000			8/31/2009	10728.11	12.500	N	N
N/A	AA081729	BLM	CPCO	59.0000000	CHEVRON	30.0000000	APC	11.0000000			8/31/2009	11331.00	12.500	N	N
N/A	AA081730	BLM	CPCO	50.0000000	CHEVRON	30.0000000	APC	20.0000000			8/31/2009	8953.56	12.500	N	N
N/A	AA081731	BLM	CPCO	50.0000000	CHEVRON	30.0000000	APC	20.0000000			8/31/2009	11426.40	12.500	N	N
N/A	AA081732	BLM	CPCO	50.0000000	CHEVRON	30.0000000	APC	20.0000000			8/31/2009	11450.52	12.500	N	N
N/A	AA081733	BLM	CPCO	50.0000000	CHEVRON	30.0000000	APC	20.0000000			8/31/2009	8314.15	12.500	N	N
N/A	AA081734	BLM	CPCO	50.0000000	CHEVRON	30.0000000	APC	20.0000000			8/31/2009	11426.76	12.500	N	N
N/A	AA081742	BLM	CPCO	59.0000000	CHEVRON	30.0000000	APC	11.0000000			8/31/2009	6949.69	16.670	N	N
N/A	AA081743	BLM	CPCO	59.0000000	CHEVRON	30.0000000	APC	11.0000000			8/31/2009	5575.77	16.670	N	N
N/A	AA081744	BLM	CPCO	59.0000000	CHEVRON	30.0000000	APC	11.0000000			8/31/2009	5623.74	16.670	N	N
N/A	AA081745	BLM	CPCO	59.0000000	CHEVRON	30.0000000	APC	11.0000000			8/31/2009	5755.59	16.670	N	N
N/A	AA081746	BLM	CPCO	59.0000000	CHEVRON	30.0000000	APC	11.0000000			8/31/2009	5647.59	16.670	N	N
N/A	AA081747	BLM	CPCO	59.0000000	CHEVRON	30.0000000	APC	11.0000000			8/31/2009	5623.56	16.670	N	N
N/A	AA081748	BLM	CPCO	59.0000000	CHEVRON	30.0000000	APC	11.0000000			8/31/2009	5623.47	16.670	N	N
N/A	AA081749	BLM	CPCO	59.0000000	CHEVRON	30.0000000	APC	11.0000000			8/31/2009	5755.41	16.670	N	N
N/A	AA081750	BLM	CPCO	59.0000000	CHEVRON	30.0000000	APC	11.0000000			8/31/2009	7674.36	16.670	N	N
N/A	AA081751	BLM	CPCO	59.0000000	CHEVRON	30.0000000	APC	11.0000000			8/31/2009	7461.00	16.670	N	N
N/A	AA081752	BLM	CPCO	59.0000000	CHEVRON	30.0000000	APC	11.0000000			8/31/2009	5755.50	16.670	N	N
N/A	AA081753	BLM	CPCO	59.0000000	CHEVRON	30.0000000	APC	11.0000000			8/31/2009	5755.77	16.670	N	N
N/A	AA081754	BLM	CPCO	59.0000000	CHEVRON	30.0000000	APC	11.0000000			8/31/2009	5599.53	16.670	N	N
N/A	AA081755	BLM	CPCO	59.0000000	CHEVRON	30.0000000	APC	11.0000000			8/31/2009	5599.53	16.670	N	N
N/A	AA081756	BLM	CPCO	59.0000000	CHEVRON	30.0000000	APC	11.0000000			8/31/2009	5599.44	16.670	N	N
N/A	AA081757	BLM	CPCO	59.0000000	CHEVRON	30.0000000	APC	11.0000000			7/31/2009	5755.50	16.670	N	N
N/A	AA081758	BLM	CPCO	59.0000000	CHEVRON	30.0000000	APC	11.0000000			8/31/2009	5755.50	16.670	N	N
N/A	AA081759	BLM	CPCO	59.0000000	CHEVRON	30.0000000	APC	11.0000000			8/31/2009	5743.26	16.670	N	N
N/A	AA081760	BLM	CPCO	59.0000000	CHEVRON	30.0000000	APC	11.0000000			8/31/2009	5755.23	16.670	N	N
N/A	AA081761	BLM	CPCO	59.0000000	CHEVRON	30.0000000	APC	11.0000000			8/31/2009	5718.60	16.670	N	N
N/A	AA081762	BLM	CPCO	59.0000000	CHEVRON	30.0000000	APC	11.0000000			8/31/2009	5755.41	16.670	N	N
N/A	AA081763	BLM	CPCO	59.0000000	CHEVRON	30.0000000	APC	11.0000000			8/31/2009	5743.04	16.670	N	N
N/A	AA081764	BLM	CPCO	59.0000000	CHEVRON	30.0000000	APC	11.0000000			8/31/2009	5755.32	16.670	N	N
N/A	AA081765	BLM	CPCO	59.0000000	CHEVRON	30.0000000	APC	11.0000000			8/31/2009	5718.60	16.670	N	N
N/A	AA081766	BLM	CPCO	59.0000000	CHEVRON	30.0000000	APC	11.0000000			8/31/2009	5755.50	16.670	N	N
N/A	AA081767	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	4284.70	16.670	N	N
N/A	AA081768	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	5069.80	16.670	N	N
N/A	AA081769	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	8052.15	16.670	N	N
N/A	AA081770	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	5755.68	16.670	N	N
N/A	AA081771	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	5578.92	16.670	N	N
N/A	AA081772	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	5755.59	16.670	N	N
N/A	AA081773	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	5578.83	16.670	N	N
N/A	AA081774	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	6401.40	16.670	N	N
N/A	AA081775	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	6410.30	16.670	N	N
N/A	AA081776	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	5756.04	16.670	N	N
N/A	AA081777	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	4987.80	16.670	N	N
N/A	AA081778	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	5756.13	16.670	N	N
N/A	AA081779	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	5756.04	16.670	N	N
N/A	AA081780	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	5749.95	16.670	N	N
N/A	AA081781	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	5723.77	16.670	N	N
N/A	AA081782	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	5755.77	16.670	N	N

UNIT	AGENCY LEASE NO	LESSOR	NOTIFICATION LESSEE NAME	NOTIFICATION LESSEE WI	OTHER WIO NAME	OTHER WIO WI	OTHER WIO NAME	OTHER WIO WI	OTHER WIO NAME	OTHER WIO WI	EXPIRATION	ACRES	ROYALTY	NET PROFIT	SLIDING
N/A	AA081783	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	5743.62	16.670	N	N
N/A	AA081784	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	5754.06	16.670	N	N
N/A	AA081785	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	5719.77	16.670	N	N
N/A	AA081786	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	5755.59	16.670	N	N
N/A	AA081787	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	5743.53	16.670	N	N
N/A	AA081788	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	5755.68	16.670	N	N
N/A	AA081789	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	5719.68	16.670	N	N
N/A	AA081790	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	5755.59	16.670	N	N
N/A	AA081791	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	5743.53	16.670	N	N
N/A	AA081792	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	5755.59	16.670	N	N
N/A	AA081793	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	5715.90	16.670	N	N
N/A	AA081794	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	5612.13	16.670	N	N
N/A	AA081795	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	5756.04	16.670	N	N
N/A	AA081796	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	5695.92	16.670	N	N
N/A	AA081797	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	5755.77	16.670	N	N
N/A	AA081798	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	5581.80	16.670	N	N
N/A	AA081799	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	5755.86	16.670	N	N
N/A	AA081800	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	5695.83	16.670	N	N
N/A	AA081801	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	5755.68	16.670	N	N
N/A	AA081802	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	5671.62	16.670	N	N
N/A	AA081803	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	5755.68	16.670	N	N
N/A	AA081804	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	5695.65	16.670	N	N
N/A	AA081805	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	5755.59	16.670	N	N
N/A	AA081806	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	5671.53	16.670	N	N
N/A	AA081807	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	5755.59	16.670	N	N
N/A	AA081808	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	5755.41	16.670	N	N
N/A	AA081809	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	5695.65	16.670	N	N
N/A	AA081810	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	5671.44	16.670	N	N
N/A	AA081811	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	5755.50	16.670	N	N
N/A	AA081812	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	5695.56	16.670	N	N
N/A	AA081813	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	5755.32	16.670	N	N
N/A	AA081814	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	5675.35	16.670	N	N
N/A	AA081815	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	5755.50	16.670	N	N
N/A	AA081816	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	5755.23	16.670	N	N
N/A	AA081817	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	8206.25	16.670	N	N
N/A	AA081818	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	5647.95	16.670	N	N
N/A	AA081819	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	5755.86	16.670	N	N
N/A	AA081820	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	5647.68	16.670	N	N
N/A	AA081821	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	5755.68	16.670	N	N
N/A	AA081822	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	5623.56	16.670	N	N
N/A	AA081823	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	5755.59	16.670	N	N
N/A	AA081824	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	5755.59	16.670	N	N
N/A	AA081825	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	5755.59	16.670	N	N
N/A	AA081826	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	5647.50	16.670	N	N
N/A	AA081827	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	5755.41	16.670	N	N
N/A	AA081828	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	5755.50	16.670	N	N
N/A	AA081829	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	5623.38	16.670	N	N
N/A	AA081830	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	5623.47	16.670	N	N
N/A	AA081831	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	5755.32	16.670	N	N
N/A	AA081832	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	5599.62	16.670	N	N
N/A	AA081833	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	5755.59	16.670	N	N
N/A	AA081834	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	5755.50	16.670	N	N
N/A	AA081835	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	5755.41	16.670	N	N

UNIT	AGENCY LEASE NO	LESSOR	NOTIFICATION LESSEE NAME	NOTIFICATION LESSEE WI	OTHER WIO NAME	OTHER WIO WI	OTHER WIO NAME	OTHER WIO WI	OTHER WIO NAME	OTHER WIO WI	EXPIRATION	ACRES	ROYALTY	NET PROFIT	SLIDING
N/A	AA081836	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	5599.44	16.670	N	N
N/A	AA081837	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	5755.50	16.670	N	N
N/A	AA081838	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	5755.50	16.670	N	N
N/A	AA081839	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	5755.41	16.670	N	N
N/A	AA081840	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	5599.44	16.670	N	N
N/A	AA081841	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	5575.50	16.670	N	N
N/A	AA081842	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	5743.26	16.670	N	N
N/A	AA081843	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	5718.60	16.670	N	N
N/A	AA081844	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	5755.50	16.670	N	N
N/A	AA081845	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	5755.41	16.670	N	N
N/A	AA081846	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	10232.00	16.670	N	N
N/A	AA081847	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	11334.24	12.500	N	N
N/A	AA081848	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	11401.38	12.500	N	N
N/A	AA081849	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	11376.18	12.500	N	N
N/A	AA081850	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	11401.56	12.500	N	N
N/A	AA081851	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	8313.50	12.500	N	N
N/A	AA081852	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	11361.42	12.500	N	N
N/A	AA081853	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	10312.88	12.500	N	N
N/A	AA081854	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	5117.00	12.500	N	N
N/A	AA081855	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	11631.18	12.500	N	N
N/A	AA081856	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	5755.50	16.670	N	N
N/A	AA081857	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	5647.68	16.670	N	N
N/A	AA081858	BLM	CPAI	78.0000000	APC	22.0000000					8/31/2009	5720.22	16.670	N	N
N/A	AA084123	BLM	CPAI	78.0000000	APC	22.0000000					09/30/2012	5696.00	16.670	N	N
N/A	AA084124	BLM	CPAI	78.0000000	APC	22.0000000					09/30/2012	5672.00	16.670	N	N
N/A	AA084125	BLM	CPAI	78.0000000	APC	22.0000000					09/30/2012	5648.00	16.670	N	N
N/A	AA084126	BLM	CPAI	78.0000000	APC	22.0000000					09/30/2012	5756.00	16.670	N	N
N/A	AA084127	BLM	CPAI	78.0000000	APC	22.0000000					09/30/2012	5648.00	16.670	N	N
N/A	AA084128	BLM	CPAI	78.0000000	APC	22.0000000					09/30/2012	5756.00	16.670	N	N
N/A	AA084129	BLM	CPAI	78.0000000	APC	22.0000000					09/30/2012	5756.00	16.670	N	N
N/A	AA084130	BLM	CPAI	78.0000000	APC	22.0000000					09/30/2012	5648.00	16.670	N	N
N/A	AA084131	BLM	CPAI	60.0000000	APC	40.0000000					09/30/2012	5576.00	16.670	N	N
N/A	AA084132	BLM	CPAI	60.0000000	APC	40.0000000					09/30/2012	4238.00	16.670	N	N
N/A	AA084133	BLM	CPAI	60.0000000	APC	40.0000000					09/30/2012	4881.00	16.670	N	N
N/A	AA084134	BLM	CPAI	60.0000000	APC	40.0000000					09/30/2012	5578.00	16.670	N	N
N/A	AA084135	BLM	CPAI	60.0000000	APC	40.0000000					09/30/2012	5756.00	16.670	N	N
N/A	AA084136	BLM	CPAI	60.0000000	APC	40.0000000					09/30/2012	5756.00	16.670	N	N
N/A	AA084137	BLM	CPAI	60.0000000	APC	40.0000000					09/30/2012	6465.00	16.670	N	N
N/A	AA084138	BLM	CPAI	60.0000000	APC	40.0000000					09/30/2012	8142.00	16.670	N	N
N/A	AA084139	BLM	CPAI	60.0000000	APC	40.0000000					09/30/2012	5756.00	16.670	N	N
N/A	AA084140	BLM	CPAI	56.0000000	PAAI	22.0000000	APC	22.0000000			09/30/2012	240.00	16.670	N	N
N/A	AA084142	BLM	CPAI	60.0000000	APC	40.0000000					09/30/2012	11453.00	12.500	N	N
N/A	AA084143	BLM	CPAI	60.0000000	APC	40.0000000					09/30/2012	11453.00	12.500	N	N
N/A	AA084144	BLM	CPAI	60.0000000	APC	40.0000000					09/30/2012	11428.00	12.500	N	N
N/A	AA084145	BLM	CPAI	60.0000000	APC	40.0000000					09/30/2012	11453.00	12.500	N	N
N/A	AA084147	BLM	CPAI	60.0000000	APC	40.0000000					09/30/2012	11453.00	12.500	N	N
N/A	AA084149	BLM	CPAI	60.0000000	APC	40.0000000					09/30/2012	11429.00	12.500	N	N
N/A	AA084150	BLM	CPAI	60.0000000	APC	40.0000000					09/30/2012	11429.00	12.500	N	N
N/A	AA084157	BLM	CPAI	60.0000000	APC	40.0000000					09/30/2012	11358.00	12.500	N	N
N/A	AA084158	BLM	CPAI	60.0000000	APC	40.0000000					09/30/2012	11335.00	12.500	N	N
N/A	AA084160	BLM	CPAI	78.0000000	APC	22.0000000					09/30/2012	11476.00	12.500	N	N
N/A	AA084168	BLM	CPAI	78.0000000	APC	22.0000000					09/30/2012	11451.00	12.500	N	N
N/A	AA084169	BLM	CPAI	78.0000000	APC	22.0000000					09/30/2012	11427.00	12.500	N	N

UNIT	AGENCY LEASE NO	LESSOR	NOTIFICATION LESSEE NAME	NOTIFICATION LESSEE WI	OTHER WIO NAME	OTHER WIO WI	OTHER WIO NAME	OTHER WIO WI	OTHER WIO NAME	OTHER WIO WI	EXPIRATION	ACRES	ROYALTY	NET PROFIT	SLIDING
N/A	AA084175	BLM	CPAI	78.0000000	APC	22.0000000					09/30/2012	11403.00	12.500	N	N
N/A	AA084180	BLM	CPAI	60.0000000	APC	40.0000000					09/30/2012	11499.00	12.500	N	N
N/A	AA084181	BLM	CPAI	60.0000000	APC	40.0000000					09/30/2012	11474.00	12.500	N	N
N/A	AA084182	BLM	CPAI	60.0000000	APC	40.0000000					09/30/2012	12546.00	12.500	N	N
N/A	ADL028249	ALASKA	CPAI	100.0000000							10/01/1993	2560.00	12.500	N	N
N/A	ADL047466	ALASKA	CPAI	50.0000000	EM AK	50.0000000					09/30/1979	2560.00	12.500	N	N
N/A	ADL047468	ALASKA	EM AK (2)	50.0000000	CHEVRON	50.0000000					09/30/1979	2437.00	12.500	N	N
N/A	ADL047527	ALASKA	EM	50.0000000	CPAI	50.0000000					09/30/1979	2523.00	12.500	N	N
N/A	ADL065406	ALASKA	CPAI	100.0000000		0.0000000					08/10/2000	2472.59	12.500	N	N
N/A	ADL355036	ALASKA	CPAI	87.5000000	PAAI	12.5000000					07/31/1993	5760.00	12.500	30.000	N
N/A	ADL355037	ALASKA	CPAI	93.7500000	PAAI	6.2500000					07/31/1993	5724.00	12.500	30.000	N
N/A	ADL355038	ALASKA	CPAI	93.7500000	PAAI	6.2500000					07/31/1993	5760.00	12.500	30.000	N
N/A	ADL355039	ALASKA	CPAI	93.7500000	PAAI	6.2500000					07/31/1993	5645.24	12.500	30.000	N
N/A	ADL364477	ALASKA	CPAI	56.0000000	PAAI	22.0000000	APC	22.0000000			07/31/1994	3840.00	12.500	30.000	N
N/A	ADL364478	ALASKA	CPAI	56.0000000	PAAI	22.0000000	APC	22.0000000			07/31/1994	3840.00	12.500	30.000	N
N/A	ADL371024	ALASKA	CPCO	100.0000000							08/31/1997	2560.00	16.667	N	N
N/A	ADL388401	ALASKA	CPAI	75.0000000	MURPHY	25.0000000					12/31/2004	2422.94	16.667	N	N
N/A	ADL388402	ALASKA	BPXA	56.0000000	CHEVRON	44.0000000					12/31/2004	2424.41	16.667	N	N
N/A	ADL388404	ALASKA	BPXA	56.0000000	CHEVRON	44.0000000					12/31/2004	1280.00	16.667	N	N
N/A	ADL388405	ALASKA	BPXA	56.0000000	CHEVRON	44.0000000					12/31/2004	2544.00	16.667	N	N
N/A	ADL388406	ALASKA	BPXA	56.0000000	CHEVRON	44.0000000					12/31/2004	2560.00	16.667	N	N
N/A	ADL388407	ALASKA	BPXA	56.0000000	CHEVRON	44.0000000					12/31/2004	2560.00	16.667	N	N
N/A	ADL388408	ALASKA	BPXA	56.0000000	CHEVRON	44.0000000					12/31/2004	2555.00	16.667	N	N
N/A	ADL388411	ALASKA	BPXA	100.0000000							12/31/2004	2029.50	16.667	N	N
N/A	ADL388412	ALASKA	BPXA	100.0000000							12/31/2004	2549.63	16.667	N	N
N/A	ADL388413	ALASKA	BPXA	100.0000000							12/31/2004	2501.00	16.667	N	N
N/A	ADL388414	ALASKA	CPAI	75.0000000	MURPHY	25.0000000					12/31/2004	2560.00	16.667	N	N
N/A	ADL388415	ALASKA	CPAI	75.0000000	MURPHY	25.0000000					12/31/2004	2560.00	16.667	N	N
N/A	ADL388416	ALASKA	CPAI	75.0000000	MURPHY	25.0000000					12/31/2004	2560.00	16.667	N	N
N/A	ADL388417	ALASKA	CPAI	75.0000000	MURPHY	25.0000000					12/31/2004	2560.00	16.667	N	N
N/A	ADL388418	ALASKA	CPAI	75.0000000	MURPHY	25.0000000					12/31/2004	1827.17	16.667	N	N
N/A	ADL388423	ALASKA	CPAI	65.7142900	MURPHY	34.2857100					12/31/2004	460.50	16.667	N	N
N/A	ADL388424	ALASKA	CPAI	75.0000000	MURPHY	25.0000000					12/31/2004	2466.71	16.667	N	N
N/A	ADL388427	ALASKA	BPXA	32.3260000	CPAI	5.0000000	EM	37.2750000	CHEVRON	25.3990000	12/31/2004	2734.38	16.667	N	N
N/A	ADL388428	ALASKA	BPXA	56.0000000	CHEVRON	44.0000000					12/31/2004	546.03	16.667	N	N
N/A	ADL388429	ALASKA	BPXA	32.3260000	CPAI	5.0000000	EM	37.2750000	CHEVRON	25.3990000	12/31/2004	2362.92	16.667	N	N
N/A	ADL388430	ALASKA	BPXA	32.3260000	CPAI	5.0000000	EM	37.2750000	CHEVRON	25.3990000	12/31/2004	2923.74	16.667	N	N
N/A	ADL388431	ALASKA	CPAI	100.0000000							12/31/2004	2560.00	16.667	N	N
N/A	ADL388432	ALASKA	CPAI	100.0000000							12/31/2004	2560.00	16.667	N	N
N/A	ADL388433	ALASKA	CPAI	100.0000000							12/31/2004	1280.00	16.667	N	N
N/A	ADL388441	ALASKA	BPXA	100.0000000							12/31/2004	2561.70	16.667	N	N
N/A	ADL388442	ALASKA	CPAI	65.7142900	MURPHY	34.2857100					12/31/2004	2790.59	16.667	N	N
N/A	ADL388443	ALASKA	CPAI	75.0000000	MURPHY	25.0000000					12/31/2004	2469.00	16.667	N	N
N/A	ADL388444	ALASKA	CPAI	65.7142900	MURPHY	34.2857100					12/31/2004	1968.33	16.667	N	N
N/A	ADL388447	ALASKA	CPAI	75.0000000	MURPHY	25.0000000					12/31/2004	2377.05	16.667	N	N
N/A	ADL388449	ALASKA	BPXA	100.0000000							12/31/2004	318.67	16.667	N	N
N/A	ADL388450	ALASKA	BPXA	56.0000000	CHEVRON	44.0000000					12/31/2004	2560.00	16.667	N	N
N/A	ADL388451	ALASKA	BPXA	56.0000000	CHEVRON	44.0000000					12/31/2004	2560.00	16.667	N	N
N/A	ADL388453	ALASKA	BPXA	56.0000000	CHEVRON	44.0000000					12/31/2004	847.49	16.667	N	N
N/A	ADL388454	ALASKA	BPXA	56.0000000	CHEVRON	44.0000000					12/31/2004	2560.00	16.667	N	N
N/A	ADL388455	ALASKA	CPAI	65.7142900	MURPHY	34.2857100					12/31/2004	2103.00	16.667	N	N
N/A	ADL388456	ALASKA	BPXA	56.0000000	CHEVRON	44.0000000					12/31/2004	1046.37	16.667	N	N
N/A	ADL388457	ALASKA	CPAI	65.7142900	MURPHY	34.2857100					12/31/2004	2114.57	16.667	N	N

UNIT	AGENCY LEASE NO	LESSOR	NOTIFICATION LESSEE NAME	NOTIFICATION LESSEE WI	OTHER WIO NAME	OTHER WIO WI	OTHER WIO NAME	OTHER WIO WI	OTHER WIO NAME	OTHER WIO WI	EXPIRATION	ACRES	ROYALTY	NET PROFIT	SLIDING
N/A	ADL388458	ALASKA	BPXA	56.0000000	CHEVRON	44.0000000					12/31/2004	1382.02	16.667	N	N
N/A	ADL388459	ALASKA	BPXA	56.0000000	CHEVRON	44.0000000					12/31/2004	385.76	16.667	N	N
N/A	ADL388461	ALASKA	BPXA	32.3260000	CPAI	5.0000000	EM	37.2750000	CHEVRON	25.3990000	12/31/2004	1867.90	16.667	N	N
N/A	ADL388462	ALASKA	BPXA	32.3260000	CPAI	5.0000000	EM	37.2750000	CHEVRON	25.3990000	12/31/2004	1351.93	16.667	N	N
N/A	ADL388463	ALASKA	CPAI	100.0000000							12/31/2004	2916.50	16.667	N	N
N/A	ADL388464	ALASKA	CPAI	100.0000000							12/31/2004	1798.41	16.667	N	N
N/A	ADL388465	ALASKA	CPAI	100.0000000							12/31/2004	1157.00	16.667	N	N
N/A	ADL388466	ALASKA	CPAI	100.0000000							12/31/2004	1752.07	16.667	N	N
N/A	ADL388486	ALASKA	CPAI	65.7142900	MURPHY	34.2857100					12/31/2004	2783.13	16.667	N	N
N/A	ADL388495	ALASKA	CPAI	56.0000000	APC	22.0000000	PAAI	22.0000000			12/31/2004	3978.50	16.667	N	N
N/A	ADL388497	ALASKA	CPAI	100.0000000							12/31/2004	5204.52	16.667	N	N
N/A	ADL388498	ALASKA	CPAI	56.0000000	PAAI	22.0000000	APC	22.0000000			12/31/2004	5044.76	16.667	N	N
N/A	ADL388499	ALASKA	CPAI	56.0000000	APC	22.0000000	PAAI	22.0000000			12/31/2004	1304.05	16.667	N	N
N/A	ADL388500	ALASKA	CPAI	56.0000000	PAAI	22.0000000	APC	22.0000000			12/31/2004	929.50	16.667	N	N
N/A	ADL388501	ALASKA	CPAI	56.0000000	APC	22.0000000	PAAI	22.0000000			12/31/2004	1708.73	16.667	N	N
N/A	ADL388502	ALASKA	CPAI	100.0000000							12/31/2004	2560.00	16.667	N	N
N/A	ADL388503	ALASKA	CPAI	100.0000000							12/31/2004	2560.00	16.667	N	N
N/A	ADL388504	ALASKA	CPAI	100.0000000							12/31/2004	2555.00	16.667	N	N
N/A	ADL388505	ALASKA	CPAI	56.0000000	PAAI	22.0000000	APC	22.0000000			12/31/2004	1521.22	16.667	N	N
N/A	ADL388506	ALASKA	CPAI	56.0000000	APC	22.0000000	PAAI	22.0000000			12/31/2004	1847.99	16.667	N	N
N/A	ADL388507	ALASKA	CPAI	56.0000000	APC	22.0000000	PAAI	22.0000000			12/31/2004	3119.72	16.667	N	N
N/A	ADL388508	ALASKA	CPAI	56.0000000	PAAI	22.0000000	APC	22.0000000			12/31/2004	2560.00	16.667	N	N
N/A	ADL388509	ALASKA	CPAI	56.0000000	APC	22.0000000	PAAI	22.0000000			12/31/2004	2560.00	16.667	N	N
N/A	ADL388510	ALASKA	CPAI	56.0000000	PAAI	22.0000000	APC	22.0000000			12/31/2004	2543.00	16.667	N	N
N/A	ADL388511	ALASKA	CPAI	56.0000000	APC	22.0000000	PAAI	22.0000000			12/31/2004	1915.00	16.667	N	N
N/A	ADL388512	ALASKA	CPAI	56.0000000	APC	22.0000000	PAAI	22.0000000			12/31/2004	1280.00	16.667	N	N
N/A	ADL388513	ALASKA	CPAI	56.0000000	APC	22.0000000	PAAI	22.0000000			12/31/2004	1280.00	16.667	N	N
N/A	ADL388514	ALASKA	CPAI	56.0000000	APC	22.0000000	PAAI	22.0000000			12/31/2004	2295.89	16.667	N	N
N/A	ADL388515	ALASKA	CPAI	56.0000000	APC	22.0000000	PAAI	22.0000000			12/31/2004	1906.00	16.667	N	N
N/A	ADL388530	ALASKA	BPXA	100.0000000							12/31/2004	1665.46	16.667	N	N
N/A	ADL388531	ALASKA	BPXA	100.0000000							12/31/2004	1067.40	16.667	N	N
N/A	ADL388532	ALASKA	BPXA	100.0000000							12/31/2004	1259.55	16.667	N	N
N/A	ADL388533	ALASKA	BPXA	100.0000000							12/31/2004	689.44	16.667	N	N
N/A	ADL388539	ALASKA	CPCO	100.0000000							12/31/2004	2560.00	16.667	N	N
N/A	ADL388540	ALASKA	CPAI	50.0000000	CHEVRON	50.0000000					12/31/2004	2198.00	16.667	N	N
N/A	ADL388541	ALASKA	CPAI	50.0000000	CHEVRON	50.0000000					12/31/2004	2560.00	16.667	N	N
N/A	ADL388542	ALASKA	CPAI	50.0000000	CHEVRON	50.0000000					12/31/2004	2161.39	16.667	N	N
N/A	ADL388546	ALASKA	CPCO	100.0000000							12/31/2004	2274.59	16.667	N	N
N/A	ADL388549	ALASKA	CPAI	50.0000000	CHEVRON	50.0000000					12/31/2004	2637.72	16.667	N	N
N/A	ADL388564	ALASKA	CPAI	56.0000000	APC	22.0000000	PAAI	22.0000000			12/31/2004	2523.21	16.667	N	N
N/A	ADL388565	ALASKA	CPAI	56.0000000	PAAI	22.0000000	APC	22.0000000			12/31/2004	1967.78	16.667	N	N
N/A	ADL388566	ALASKA	CPAI	56.0000000	PAAI	22.0000000	APC	22.0000000			12/31/2004	2167.74	16.667	N	N
N/A	ADL388567	ALASKA	CPAI	56.0000000	APC	22.0000000	PAAI	22.0000000			12/31/2004	2986.31	16.667	N	N
N/A	ADL388568	ALASKA	CPAI	56.0000000	PAAI	22.0000000	APC	22.0000000			12/31/2004	2782.72	16.667	N	N
N/A	ADL388571	ALASKA	CPAI	100.0000000							12/31/2004	2766.36	16.667	N	N
N/A	ADL388572	ALASKA	CPAI	100.0000000							12/31/2004	1968.24	16.667	N	N
N/A	ADL388573	ALASKA	PAAI	100.0000000							12/31/2004	2786.59	16.667	N	N
N/A	ADL388574	ALASKA	CPAI	100.0000000							12/31/2004	1920.00	16.667	N	N
N/A	ADL388575	ALASKA	PAAI	100.0000000							12/31/2004	2560.00	16.667	N	N
N/A	ADL388577	ALASKA	CPAI	100.0000000							12/31/2004	1280.00	16.667	N	N
N/A	ADL388578	ALASKA	CPAI	100.0000000							12/31/2004	1280.00	16.667	N	N
N/A	ADL388585	ALASKA	BPXA	100.0000000							12/31/2004	1280.00	16.667	N	N
N/A	ADL388607	ALASKA	CPCO	100.0000000							12/31/2004	2440.02	16.667	N	N

UNIT	AGENCY LEASE NO	LESSOR	NOTIFICATION LESSEE NAME	NOTIFICATION LESSEE WI	OTHER WIO NAME	OTHER WIO WI	OTHER WIO NAME	OTHER WIO WI	OTHER WIO NAME	OTHER WIO WI	EXPIRATION	ACRES	ROYALTY	NET PROFIT	SLIDING
N/A	ADL388608	ALASKA	CPCO	100.0000000							12/31/2004	2366.99	16.667	N	N
N/A	ADL388609	ALASKA	CPCO	100.0000000							12/31/2004	757.38	16.667	N	N
N/A	ADL388610	ALASKA	CPCO	100.0000000							12/31/2004	647.34	16.667	N	N
N/A	ADL389001	ALASKA	CPAI	50.0000000	CHEVRON	50.0000000					10/31/2005	5760.00	12.500	N	N
N/A	ADL389002	ALASKA	CPAI	50.0000000	CHEVRON	50.0000000					10/31/2005	5760.00	12.500	N	N
N/A	ADL389003	ALASKA	CPAI	50.0000000	CHEVRON	50.0000000					10/31/2005	5725.00	12.500	N	N
N/A	ADL389004	ALASKA	CPAI	50.0000000	CHEVRON	50.0000000					10/31/2005	5749.00	12.500	N	N
N/A	ADL389005	ALASKA	CPAI	50.0000000	CHEVRON	50.0000000					10/31/2005	5760.00	12.500	N	N
N/A	ADL389006	ALASKA	CPAI	50.0000000	CHEVRON	50.0000000					10/31/2005	5760.00	12.500	N	N
N/A	ADL389007	ALASKA	CPAI	50.0000000	CHEVRON	50.0000000					10/31/2005	5633.00	12.500	N	N
N/A	ADL389008	ALASKA	CPAI	50.0000000	CHEVRON	50.0000000					10/31/2005	5655.00	12.500	N	N
N/A	ADL389009	ALASKA	CPAI	50.0000000	CHEVRON	50.0000000					10/31/2005	5760.00	12.500	N	N
N/A	ADL389010	ALASKA	CPAI	30.0000000	CHEVRON	50.0000000	ENCANA	20.0000000			10/31/2005	5760.00	12.500	N	N
N/A	ADL389014	ALASKA	CPAI	30.0000000	CHEVRON	36.0000000	APC	22.0000000	ENCANA	12.0000000	10/31/2005	5609.00	12.500	N	N
N/A	ADL389015	ALASKA	CPAI	30.0000000	CHEVRON	36.0000000	APC	22.0000000	ENCANA	12.0000000	10/31/2005	5760.00	12.500	N	N
N/A	ADL389022	ALASKA	CPAI	30.0000000	CHEVRON	36.0000000	APC	22.0000000	ENCANA	12.0000000	10/31/2005	5725.00	12.500	N	N
N/A	ADL389027	ALASKA	BPXA	100.0000000							10/31/2005	5760.00	12.500	N	N
N/A	ADL389028	ALASKA	CPAI	30.0000000	CHEVRON	36.0000000	APC	22.0000000	ENCANA	12.0000000	10/31/2005	1920.00	12.500	N	N
N/A	ADL389043	ALASKA	CPAI	58.4649000	BPXA	41.5351000					10/31/2005	5760.00	12.500	N	N
N/A	ADL389044	ALASKA	CPAI	58.4649000	BPXA	41.5351000					10/31/2005	5760.00	12.500	N	N
N/A	ADL389045	ALASKA	CPAI	58.4649000	BPXA	41.5351000					10/31/2005	5760.00	12.500	N	N
N/A	ADL389046	ALASKA	CPAI	58.4649000	BPXA	41.5351000					10/31/2005	5630.00	12.500	N	N
N/A	ADL389047	ALASKA	CPAI	100.0000000							10/31/2005	5654.00	12.500	N	N
N/A	ADL389048	ALASKA	CPAI	58.4649000	BPXA	41.5351000					10/31/2005	5760.00	12.500	N	N
N/A	ADL389056	ALASKA	CPAI	100.0000000							10/31/2005	5760.00	12.500	N	N
N/A	ADL389057	ALASKA	CPAI	58.4649000	BPXA	41.5351000					10/31/2005	5760.00	12.500	N	N
N/A	ADL389065	ALASKA	BPXA	60.0000000	APC	40.0000000					10/31/2005	2560.00	12.500	N	N
N/A	ADL389066	ALASKA	BPXA	60.0000000	APC	40.0000000					10/31/2005	2560.00	12.500	N	N
N/A	ADL389067	ALASKA	BPXA	60.0000000	APC	40.0000000					10/31/2005	2560.00	12.500	N	N
N/A	ADL389068	ALASKA	BPXA	60.0000000	APC	40.0000000					10/31/2005	2560.00	12.500	N	N
N/A	ADL389069	ALASKA	BPXA	60.0000000	APC	40.0000000					10/31/2005	1920.00	12.500	N	N
N/A	ADL389070	ALASKA	BPXA	60.0000000	APC	40.0000000					10/31/2005	1224.00	12.500	N	N
N/A	ADL389071	ALASKA	BPXA	60.0000000	APC	40.0000000					10/31/2005	2560.00	12.500	N	N
N/A	ADL389072	ALASKA	BPXA	60.0000000	APC	40.0000000					10/31/2005	1280.00	12.500	N	N
N/A	ADL389073	ALASKA	BPXA	60.0000000	APC	40.0000000					10/31/2005	1280.00	12.500	N	N
N/A	ADL389074	ALASKA	BPXA	60.0000000	APC	40.0000000					10/31/2005	2450.00	12.500	N	N
N/A	ADL389075	ALASKA	BPXA	60.0000000	APC	40.0000000					10/31/2005	1280.00	12.500	N	N
N/A	ADL389076	ALASKA	BPXA	60.0000000	APC	40.0000000					10/31/2005	2461.00	12.500	N	N
N/A	ADL389081	ALASKA	CPAI	78.0000000	APC	22.0000000					10/31/2005	1540.38	12.500	N	N
N/A	ADL389082	ALASKA	CPAI	78.0000000	APC	22.0000000					10/31/2005	2560.00	12.500	N	N
N/A	ADL389083	ALASKA	CPAI	78.0000000	APC	22.0000000					10/31/2005	1391.22	12.500	N	N
N/A	ADL389084	ALASKA	CPAI	56.0000000	PAAI	22.0000000	APC	22.0000000			10/31/2005	2560.00	12.500	N	N
N/A	ADL389085	ALASKA	CPAI	78.0000000	APC	22.0000000					10/31/2005	2560.00	12.500	N	N
N/A	ADL389086	ALASKA	CPAI	78.0000000	APC	22.0000000					10/31/2005	2544.00	12.500	N	N
N/A	ADL389087	ALASKA	CPAI	78.0000000	APC	22.0000000					10/31/2005	2555.00	12.500	N	N
N/A	ADL389096	ALASKA	CPAI	100.0000000							10/31/2005	2560.00	12.500	N	N
N/A	ADL389097	ALASKA	CPAI	100.0000000							10/31/2005	2533.00	12.500	N	N
N/A	ADL389098	ALASKA	BPXA	60.0000000	APC	40.0000000					10/31/2005	2533.00	12.500	N	N
N/A	ADL389099	ALASKA	BPXA	60.0000000	APC	40.0000000					10/31/2005	2544.00	12.500	N	N
N/A	ADL389100	ALASKA	BPXA	60.0000000	APC	40.0000000					10/31/2005	2560.00	12.500	N	N
N/A	ADL389101	ALASKA	BPXA	60.0000000	APC	40.0000000					10/31/2005	2560.00	12.500	N	N
N/A	ADL389102	ALASKA	BPXA	60.0000000	APC	40.0000000					10/31/2005	2555.00	12.500	N	N
N/A	ADL389105	ALASKA	BPXA	60.0000000	APC	40.0000000					10/31/2005	2555.00	12.500	N	N

UNIT	AGENCY LEASE NO	LESSOR	NOTIFICATION LESSEE NAME	NOTIFICATION LESSEE WI	OTHER WIO NAME	OTHER WIO WI	OTHER WIO NAME	OTHER WIO WI	OTHER WIO NAME	OTHER WIO WI	EXPIRATION	ACRES	ROYALTY	NET PROFIT	SLIDING
N/A	ADL389106	ALASKA	CPAI	75.0000000	MURPHY	25.0000000					10/31/2005	2560.00	12.500	N	N
N/A	ADL389112	ALASKA	CPAI	75.0000000	MURPHY	25.0000000					10/31/2005	2544.00	12.500	N	N
N/A	ADL389129	ALASKA	CPAI	100.0000000							10/31/2005	2560.00	12.500	N	N
N/A	ADL389130	ALASKA	CPAI	100.0000000							10/31/2005	2560.00	12.500	N	N
N/A	ADL389131	ALASKA	CPAI	100.0000000							10/31/2005	2560.00	12.500	N	N
N/A	ADL389134	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	11/30/2005	640.00	12.500	N	N
N/A	ADL389135	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	11/30/2005	1239.00	12.500	N	N
N/A	ADL389136	ALASKA	CPAI	78.0000000	APC	22.0000000					10/31/2005	1920.00	12.500	N	N
N/A	ADL389137	ALASKA	CPAI	78.0000000	APC	22.0000000					10/31/2005	2560.00	12.500	N	N
N/A	ADL389138	ALASKA	CPAI	78.0000000	APC	22.0000000					10/31/2005	2560.00	12.500	N	N
N/A	ADL389139	ALASKA	CPAI	100.0000000							09/30/2005	2560.00	12.500	N	N
N/A	ADL389142	ALASKA	CPAI	30.0000000	CHEVRON	36.0000000	APC	22.0000000	ENCANA	12.0000000	06/30/2006	5760.00	12.500	N	N
N/A	ADL389143	ALASKA	CPAI	30.0000000	CHEVRON	36.0000000	APC	22.0000000	ENCANA	12.0000000	06/30/2006	5760.00	12.500	N	N
N/A	ADL389144	ALASKA	CPAI	30.0000000	CHEVRON	36.0000000	APC	22.0000000	ENCANA	12.0000000	06/30/2006	5748.00	12.500	N	N
N/A	ADL389145	ALASKA	CPAI	30.0000000	CHEVRON	36.0000000	APC	22.0000000	ENCANA	12.0000000	06/30/2006	5760.00	12.500	N	N
N/A	ADL389146	ALASKA	CPAI	30.0000000	CHEVRON	36.0000000	APC	22.0000000	ENCANA	12.0000000	06/30/2006	5760.00	12.500	N	N
N/A	ADL389147	ALASKA	CPAI	30.0000000	CHEVRON	36.0000000	APC	22.0000000	ENCANA	12.0000000	06/30/2006	5725.00	12.500	N	N
N/A	ADL389148	ALASKA	CPAI	30.0000000	CHEVRON	36.0000000	APC	22.0000000	ENCANA	12.0000000	06/30/2006	5748.00	12.500	N	N
N/A	ADL389149	ALASKA	CPAI	30.0000000	CHEVRON	36.0000000	APC	22.0000000	ENCANA	12.0000000	06/30/2006	5760.00	12.500	N	N
N/A	ADL389153	ALASKA	CPAI	30.0000000	CHEVRON	50.0000000	ENCANA	20.0000000			06/30/2006	5701.00	12.500	N	N
N/A	ADL389154	ALASKA	CPAI	30.0000000	CHEVRON	36.0000000	APC	22.0000000	ENCANA	12.0000000	06/30/2006	3840.00	12.500	N	N
N/A	ADL389160	ALASKA	CPAI	100.0000000							06/30/2006	5630.00	12.500	N	N
N/A	ADL389161	ALASKA	CPAI	100.0000000							06/30/2006	5583.00	12.500	N	N
N/A	ADL389166	ALASKA	CPAI	78.0000000	APC	22.0000000					06/30/2006	2560.00	12.500	N	N
N/A	ADL389167	ALASKA	CPAI	78.0000000	APC	22.0000000					06/30/2006	1485.60	12.500	N	N
N/A	ADL389168	ALASKA	CPAI	78.0000000	APC	22.0000000					06/30/2006	2560.00	12.500	N	N
N/A	ADL389169	ALASKA	CPAI	78.0000000	APC	22.0000000					06/30/2006	2560.00	12.500	N	N
N/A	ADL389170	ALASKA	CPAI	78.0000000	APC	22.0000000					06/30/2006	2560.00	12.500	N	N
N/A	ADL389562	ALASKA	CPAI	100.0000000							11/30/2008	5760.00	12.500	N	N
N/A	ADL389563	ALASKA	CPAI	100.0000000							11/30/2008	5725.00	12.500	N	N
N/A	ADL389579	ALASKA	CPAI	100.0000000							11/30/2008	5760.00	12.500	N	N
N/A	ADL389580	ALASKA	CPAI	100.0000000							11/30/2008	5702.00	12.500	N	N
N/A	ADL389581	ALASKA	CPAI	100.0000000							11/30/2008	5760.00	12.500	N	N
N/A	ADL389602	ALASKA	CPAI	37.5000000	ENCANA	32.5000000	CHEVRON	30.0000000			11/30/2008	5587.00	12.500	N	N
N/A	ADL389610	ALASKA	CPAI	37.5000000	ENCANA	32.5000000	CHEVRON	30.0000000			11/30/2008	5760.00	12.500	N	N
N/A	ADL389611	ALASKA	CPAI	37.5000000	ENCANA	32.5000000	CHEVRON	30.0000000			11/30/2008	5725.00	12.500	N	N
N/A	ADL389612	ALASKA	CPAI	37.5000000	ENCANA	32.5000000	CHEVRON	30.0000000			11/30/2008	5760.00	12.500	N	N
N/A	ADL389613	ALASKA	CPAI	37.5000000	ENCANA	32.5000000	CHEVRON	30.0000000			11/30/2008	5760.00	12.500	N	N
N/A	ADL389614	ALASKA	CPAI	37.5000000	ENCANA	32.5000000	CHEVRON	30.0000000			11/30/2008	5725.00	12.500	N	N
N/A	ADL389615	ALASKA	CPAI	37.5000000	ENCANA	32.5000000	CHEVRON	30.0000000			11/30/2008	5748.00	12.500	N	N
N/A	ADL389616	ALASKA	CPAI	37.5000000	ENCANA	32.5000000	CHEVRON	30.0000000			11/30/2008	5760.00	12.500	N	N
N/A	ADL389617	ALASKA	CPAI	37.5000000	ENCANA	32.5000000	CHEVRON	30.0000000			11/30/2008	5725.00	12.500	N	N
N/A	ADL389619	ALASKA	CPAI	37.5000000	ENCANA	32.5000000	CHEVRON	30.0000000			11/30/2008	5760.00	12.500	N	N
N/A	ADL389620	ALASKA	CPAI	37.5000000	ENCANA	32.5000000	CHEVRON	30.0000000			11/30/2008	5760.00	12.500	N	N
N/A	ADL389621	ALASKA	CPAI	37.5000000	ENCANA	32.5000000	CHEVRON	30.0000000			11/30/2008	5748.00	12.500	N	N
N/A	ADL389622	ALASKA	CPAI	37.5000000	ENCANA	32.5000000	CHEVRON	30.0000000			11/30/2008	5748.00	12.500	30.000	N
N/A	ADL389623	ALASKA	CPAI	37.5000000	ENCANA	32.5000000	CHEVRON	30.0000000			11/30/2008	5760.00	12.500	N	33.000
N/A	ADL389628	ALASKA	CPAI	37.5000000	ENCANA	32.5000000	CHEVRON	30.0000000			11/30/2008	5760.00	12.500	N	33.000
N/A	ADL389629	ALASKA	CPAI	37.5000000	ENCANA	32.5000000	CHEVRON	30.0000000			11/30/2008	5701.00	12.500	N	33.000
N/A	ADL389630	ALASKA	CPAI	37.5000000	ENCANA	32.5000000	CHEVRON	30.0000000			11/30/2008	5760.00	12.500	N	33.000
N/A	ADL389631	ALASKA	CPAI	37.5000000	ENCANA	32.5000000	CHEVRON	30.0000000			11/30/2008	5760.00	12.500	N	N
N/A	ADL389632	ALASKA	CPAI	37.5000000	ENCANA	32.5000000	CHEVRON	30.0000000			11/30/2008	5677.00	12.500	N	N
N/A	ADL389633	ALASKA	CPAI	37.5000000	ENCANA	32.5000000	CHEVRON	30.0000000			11/30/2008	5701.00	12.500	N	N

UNIT	AGENCY LEASE NO	LESSOR	NOTIFICATION LESSEE NAME	NOTIFICATION LESSEE WI	OTHER WIO NAME	OTHER WIO WI	OTHER WIO NAME	OTHER WIO WI	OTHER WIO NAME	OTHER WIO WI	EXPIRATION	ACRES	ROYALTY	NET PROFIT	SLIDING
N/A	ADL389634	ALASKA	CPAI	37.5000000	ENCANA	32.5000000	CHEVRON	30.0000000			11/30/2008	5760.00	12.500	N	N
N/A	ADL389635	ALASKA	CPAI	37.5000000	ENCANA	32.5000000	CHEVRON	30.0000000			11/30/2008	5677.00	12.500	N	N
N/A	ADL389636	ALASKA	CPAI	37.5000000	ENCANA	32.5000000	CHEVRON	30.0000000			11/30/2008	5701.00	12.500	N	N
N/A	ADL389637	ALASKA	CPAI	37.5000000	ENCANA	32.5000000	CHEVRON	30.0000000			11/30/2008	5760.00	12.500	N	N
N/A	ADL389638	ALASKA	CPAI	37.5000000	ENCANA	32.5000000	CHEVRON	30.0000000			11/30/2008	5760.00	12.500	N	N
N/A	ADL389639	ALASKA	CPAI	37.5000000	ENCANA	32.5000000	CHEVRON	30.0000000			11/30/2008	5701.00	12.500	N	N
N/A	ADL389640	ALASKA	CPAI	37.5000000	ENCANA	32.5000000	CHEVRON	30.0000000			11/30/2008	5760.00	12.500	N	N
N/A	ADL389646	ALASKA	CPAI	37.5000000	ENCANA	32.5000000	CHEVRON	30.0000000			11/30/2008	5760.00	12.500	N	N
N/A	ADL389648	ALASKA	CPAI	37.5000000	ENCANA	32.5000000	CHEVRON	30.0000000			11/30/2008	5760.00	12.500	N	N
N/A	ADL389649	ALASKA	CPAI	37.5000000	ENCANA	32.5000000	CHEVRON	30.0000000			11/30/2008	5654.00	12.500	N	N
N/A	ADL389650	ALASKA	CPAI	37.5000000	ENCANA	32.5000000	CHEVRON	30.0000000			11/30/2008	5760.00	12.500	N	N
N/A	ADL389651	ALASKA	CPAI	37.5000000	ENCANA	32.5000000	CHEVRON	30.0000000			11/30/2008	5760.00	12.500	N	N
N/A	ADL389656	ALASKA	BPXA	38.8800000	CHEVRON	30.5600000	CPAI	30.5600000			11/30/2008	5760.00	12.500	N	N
N/A	ADL389657	ALASKA	BPXA	56.0000000	CHEVRON	44.0000000					11/30/2008	5654.00	12.500	N	N
N/A	ADL389665	ALASKA	CPAI	56.0000000	APC	22.0000000	PAAI	22.0000000			11/30/2008	5760.00	16.667	N	N
N/A	ADL389666	ALASKA	CPAI	56.0000000	APC	22.0000000	PAAI	22.0000000			11/30/2008	5583.00	16.667	N	N
N/A	ADL389669	ALASKA	CPAI	100.0000000							11/30/2008	5583.00	16.667	N	N
N/A	ADL389673	ALASKA	BPXA	60.0000000	APC	40.0000000					11/30/2008	1280.00	12.500	N	N
N/A	ADL389674	ALASKA	BPXA	60.0000000	APC	40.0000000					11/30/2008	1280.00	12.500	N	N
N/A	ADL389675	ALASKA	BPXA	60.0000000	APC	40.0000000					11/30/2008	640.00	12.500	N	N
N/A	ADL389676	ALASKA	BPXA	60.0000000	APC	40.0000000					11/30/2008	2439.00	12.500	N	N
N/A	ADL389684	ALASKA	BPXA	56.0000000	CHEVRON	44.0000000					11/30/2008	2439.00	12.500	N	N
N/A	ADL389685	ALASKA	BPXA	56.0000000	CHEVRON	44.0000000					11/30/2008	2450.00	12.500	N	N
N/A	ADL389686	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	11/30/2008	2560.00	12.500	N	N
N/A	ADL389688	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	11/30/2008	2560.00	12.500	N	N
N/A	ADL389689	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	11/30/2008	2560.00	12.500	N	N
N/A	ADL389690	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	11/30/2008	2533.00	12.500	N	N
N/A	ADL389691	ALASKA	BPXA	39.2822330	CPAI	55.2937670	UNOCAL, et al	5.0592000	EM AK	0.3648000	11/30/2008	2560.00	12.500	N	N
N/A	ADL389697	ALASKA	BPXA	39.2822330	CPAI	55.2937670	UNOCAL, et al	5.0592000	EM AK	0.3648000	11/30/2008	2533.00	12.500	N	N
N/A	ADL389698	ALASKA	BPXA	39.2822330	CPAI	55.2937670	UNOCAL, et al	5.0592000	EM AK	0.3648000	11/30/2008	2544.00	12.500	N	N
N/A	ADL389702	ALASKA	BPXA	60.0000000	APC	40.0000000					11/30/2008	2560.00	12.500	N	N
N/A	ADL389703	ALASKA	BPXA	60.0000000	APC	40.0000000					11/30/2008	2560.00	12.500	N	N
N/A	ADL389704	ALASKA	BPXA	60.0000000	APC	40.0000000					11/30/2008	2560.00	12.500	N	N
N/A	ADL389705	ALASKA	BPXA	60.0000000	APC	40.0000000					11/30/2008	2560.00	12.500	N	N
N/A	ADL389706	ALASKA	BPXA	60.0000000	APC	40.0000000					11/30/2008	2544.00	12.500	N	N
N/A	ADL389707	ALASKA	BPXA	60.0000000	APC	40.0000000					11/30/2008	2560.00	12.500	N	N
N/A	ADL389729	ALASKA	EM	100.0000000							05/31/2008	3426.78	16.667	N	N
N/A	ADL389782	ALASKA	CPAI	50.0000000	CHEVRON	50.0000000					06/30/2012	5760.00	12.500	N	N
N/A	ADL389783	ALASKA	CPAI	50.0000000	CHEVRON	50.0000000					06/30/2012	5704.00	12.500	N	N
N/A	ADL389784	ALASKA	CPAI	50.0000000	CHEVRON	50.0000000					06/30/2012	5760.00	12.500	N	N
N/A	ADL389788	ALASKA	CPAI	50.0000000	CHEVRON	50.0000000					06/30/2012	5760.00	12.500	N	N
N/A	ADL389791	ALASKA	CPAI	50.0000000	CHEVRON	50.0000000					06/30/2012	5760.00	12.500	N	N
N/A	ADL389792	ALASKA	CPAI	50.0000000	CHEVRON	50.0000000					06/30/2012	5726.00	12.500	N	N
N/A	ADL389793	ALASKA	CPAI	50.0000000	CHEVRON	50.0000000					06/30/2012	5749.00	12.500	N	N
N/A	ADL389794	ALASKA	CPAI	50.0000000	CHEVRON	50.0000000					06/30/2012	5760.00	12.500	N	N
N/A	ADL389795	ALASKA	CPAI	50.0000000	CHEVRON	50.0000000					06/30/2012	5760.00	12.500	N	N
N/A	ADL389796	ALASKA	CPAI	50.0000000	CHEVRON	50.0000000					06/30/2012	5726.00	12.500	N	N
N/A	ADL389797	ALASKA	CPAI	50.0000000	CHEVRON	50.0000000					06/30/2012	5749.00	12.500	N	N
N/A	ADL389798	ALASKA	CPAI	50.0000000	CHEVRON	50.0000000					06/30/2012	5760.00	12.500	N	N
N/A	ADL389799	ALASKA	CPAI	50.0000000	CHEVRON	50.0000000					06/30/2012	5726.00	12.500	N	N
N/A	ADL389830	ALASKA	CPAI	50.0000000	CHEVRON	50.0000000					06/30/2012	5760.00	12.500	N	N
N/A	ADL389831	ALASKA	CPAI	50.0000000	CHEVRON	50.0000000					06/30/2012	5595.56	12.500	N	N
N/A	ADL389834	ALASKA	CPAI	50.0000000	CHEVRON	50.0000000					06/30/2012	5760.00	12.500	N	N

UNIT	AGENCY LEASE NO	LESSOR	NOTIFICATION LESSEE NAME	NOTIFICATION LESSEE WI	OTHER WIO NAME	OTHER WIO WI	OTHER WIO NAME	OTHER WIO WI	OTHER WIO NAME	OTHER WIO WI	EXPIRATION	ACRES	ROYALTY	NET PROFIT	SLIDING
N/A	ADL389835	ALASKA	CPAI	50.0000000	CHEVRON	50.0000000					06/30/2012	5596.00	12.500	N	N
N/A	ADL389837	ALASKA	CPAI	50.0000000	CHEVRON	50.0000000					06/30/2012	1920.00	12.500	N	N
N/A	ADL389840	ALASKA	CPAI	50.0000000	CHEVRON	50.0000000					06/30/2012	3747.48	12.500	N	N
N/A	ADL389883	ALASKA	CPAI	50.0000000	CHEVRON	50.0000000					06/30/2012	5704.00	12.500	N	N
N/A	ADL389884	ALASKA	CPAI	50.0000000	CHEVRON	50.0000000					06/30/2012	5760.00	12.500	N	N
N/A	ADL389885	ALASKA	CPAI	50.0000000	CHEVRON	50.0000000					06/30/2012	5704.00	12.500	N	N
N/A	ADL389886	ALASKA	CPAI	50.0000000	CHEVRON	50.0000000					06/30/2012	5760.00	12.500	N	N
N/A	ADL389887	ALASKA	CPAI	50.0000000	CHEVRON	50.0000000					06/30/2012	5726.00	12.500	N	N
N/A	ADL389890	ALASKA	CPAI	50.0000000	CHEVRON	50.0000000					06/30/2012	5760.00	12.500	N	N
N/A	ADL389945	ALASKA	CPAI	100.0000000							08/31/2009	1706.07	16.667	N	N
N/A	ADL389946	ALASKA	CPAI	100.0000000							08/31/2009	2014.39	16.667	N	N
N/A	ADL389962	ALASKA	CPAI	56.0000000	PAAI	22.0000000	APC	22.0000000			08/31/2009	1268.00	16.667	N	N
N/A	ADL389963	ALASKA	CPAI	56.0000000	PAAI	22.0000000	APC	22.0000000			08/31/2009	1280.00	16.667	N	N
N/A	ADL389964	ALASKA	CPAI	56.0000000	PAAI	22.0000000	APC	22.0000000			08/31/2009	2560.00	16.667	N	N
N/A	ADL389990	ALASKA	CPAI	42.0000000	CHEVRON	36.0000000	APC	22.0000000			08/31/2009	5587.00	12.500	N	N
N/A	ADL390039	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	08/31/2009	2544.00	16.670	N	N
N/A	ADL390040	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	12/31/2008	2555.00	16.667	N	N
N/A	ADL390042	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	08/31/2009	2560.00	16.670	N	N
N/A	ADL390043	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	08/31/2009	2533.00	16.670	N	N
N/A	ADL390046	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	08/31/2009	2544.00	16.670	N	N
N/A	ADL390054	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	08/31/2009	2501.00	16.670	N	N
N/A	ADL390056	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	08/31/2009	2560.00	16.670	N	N
N/A	ADL390058	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	08/31/2009	1920.00	16.670	N	N
N/A	ADL390059	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	08/31/2009	1920.00	16.670	N	N
N/A	ADL390060	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	08/31/2009	1241.00	16.670	N	N
N/A	ADL390061	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	08/31/2009	1920.00	16.670	N	N
N/A	ADL390062	ALASKA	CPAI	55.2937670	BPXA	39.2822330	UNOCAL, et al	5.0592000	EM AK	0.3648000	08/31/2009	2491.00	16.670	N	N
N/A	ADL390067	ALASKA	BPXA	100.0000000							08/31/2009	2560.00	16.670	N	N
N/A	ADL390068	ALASKA	CPAI	56.0000000	PAAI	22.0000000	APC	22.0000000			08/31/2009	640.00	16.670	N	N
N/A	ADL390069	ALASKA	CPAI	56.0000000	PAAI	22.0000000	APC	22.0000000			08/31/2009	1280.00	16.670	N	N
N/A	ADL390070	ALASKA	CPAI	56.0000000	PAAI	22.0000000	APC	22.0000000			08/31/2009	2544.00	16.670	N	N
N/A	ADL390071	ALASKA	CPAI	56.0000000	PAAI	22.0000000	APC	22.0000000			08/31/2009	1280.00	16.670	N	N
N/A	ADL390072	ALASKA	CPAI	56.0000000	PAAI	22.0000000	APC	22.0000000			08/31/2009	2555.00	16.670	N	N
N/A	ADL390311	ALASKA	EM	37.2750000	BPXA	32.3260000	CHEVRON	26.7357900	CPAI	3.6632100	03/31/2010	165.44	20.000	N	N
N/A	ADL390312	ALASKA	EM	37.2750000	BPXA	32.3260000	CHEVRON	26.7357900	CPAI	3.6632100	03/31/2010	1280.00	20.000	N	N
N/A	ADL390313	ALASKA	EM	37.2750000	BPXA	32.3260000	CHEVRON	26.7357900	CPAI	3.6632100	03/31/2010	464.28	20.000	N	N
N/A	ADL390314	ALASKA	BPXA	26.6700000	CPAI	36.5000000	EM AK	36.8300000			03/31/2010	2266.86	16.667	N	N
N/A	ADL390315	ALASKA	ENCANA	38.8340000	CPAI	33.3330000	CHEVRON	27.8330000			03/31/2010	249.56	16.667	N	N
N/A	ADL390316	ALASKA	ENCANA	38.8340000	CPAI	33.3330000	CHEVRON	27.8330000			03/31/2010	1540.32	16.667	N	N
N/A	ADL390317	ALASKA	ENCANA	38.8340000	CPAI	33.3330000	CHEVRON	27.8330000			03/31/2010	379.58	16.667	N	N
N/A	ADL390318	ALASKA	ENCANA	38.8340000	CPAI	33.3330000	CHEVRON	27.8330000			03/31/2010	1537.55	16.667	N	N
N/A	ADL390319	ALASKA	ENCANA	38.8340000	CPAI	33.3330000	CHEVRON	27.8330000			03/31/2010	1501.71	16.667	N	N
N/A	ADL390323	ALASKA	CPAI	60.0000000	APC	40.0000000					03/31/2010	1931.40	16.667	N	N
N/A	ADL390324	ALASKA	CPAI	60.0000000	APC	40.0000000					03/31/2010	2445.84	16.667	N	N
N/A	ADL390335	ALASKA	CPAI	100.0000000							05/30/2010	2560.00	16.667	N	N
N/A	ADL390336	ALASKA	CPAI	100.0000000							05/30/2010	2555.00	16.667	N	N
N/A	ADL390337	ALASKA	CPAI	56.0000000	PAAI	22.0000000	APC	22.0000000			05/30/2010	1018.21	16.667	N	33.333
N/A	ADL390338	ALASKA	CPAI	56.0000000	PAAI	22.0000000	APC	22.0000000			05/30/2010	615.86	16.667	N	33.333
N/A	ADL390339	ALASKA	CPAI	56.0000000	PAAI	22.0000000	APC	22.0000000			05/30/2010	5.53	16.667	N	33.333
N/A	ADL390340	ALASKA	CPAI	56.0000000	PAAI	22.0000000	APC	22.0000000			05/30/2010	917.81	16.667	N	33.333
N/A	ADL390341	ALASKA	CPAI	56.0000000	PAAI	22.0000000	APC	22.0000000			05/30/2010	306.46	16.667	N	33.333
N/A	ADL390344	ALASKA	CPAI	56.0000000	PAAI	22.0000000	APC	22.0000000			01/31/2005	839.00	16.667	N	N
N/A	ADL390345	ALASKA	CPAI	56.0000000	APC	22.0000000	PAAI	22.0000000			01/31/2005	448.00	16.667	N	N

UNIT	AGENCY LEASE NO	LESSOR	NOTIFICATION LESSEE NAME	NOTIFICATION LESSEE WI	OTHER WIO NAME	OTHER WIO WI	OTHER WIO NAME	OTHER WIO WI	OTHER WIO NAME	OTHER WIO WI	EXPIRATION	ACRES	ROYALTY	NET PROFIT	SLIDING
N/A	ADL390346	ALASKA	CPAI	56.0000000	PAAI	22.0000000	APC	22.0000000			12/31/2004	614.00	16.667	N	N
N/A	ADL390347	ALASKA	CPAI	55.6200000	PAAI	22.0000000	APC	22.0000000	PETRO-HUNT	.3800000	10/31/2005	227.00	16.667	N	N
N/A	ADL390348	ALASKA	CPAI	56.0000000	PAAI	22.0000000	APC	22.0000000			09/30/2003	192.00	16.667	N	N
N/A	ADL390349	ALASKA	CPAI	56.0000000	PAAI	22.0000000	APC	22.0000000			12/31/2004	598.00	16.667	N	N
N/A	ADL390350	ALASKA	CPAI	56.0000000	PAAI	22.0000000	APC	22.0000000			12/31/2004	441.00	16.667	N	N
N/A	ADL390351	ALASKA	CPAI	56.0000000	APC	22.0000000	PAAI	22.0000000			12/31/2004	1123.00	16.667	N	N
N/A	ASRC_ANWR	ASRC	CHEVRON	50.0000000	BPXA	50.0000000					confid	0.00		N	N
N/A	ASRC-NPR1	ASRC	CPAI	78.0000000	APC	22.0000000					confid	0.00	0.000	N	N
N/A	ASRC-NPR1	ASRC	CPAI	78.0000000	APC	22.0000000					confid	0.00	0.000	N	N
N/A	ASRC-NPR2	ASRC	CPAI	56.0000000	APC	22.0000000	PAAI	22.0000000			08/31/2005	27783.48		N	N
N/A	ASRC-NPR3	ASRC	CPAI	78.0000000	APC	22.0000000					confid	0.00		N	N
N/A	ASRC-NPR4	ASRC	CPAI	78.0000000	APC	22.0000000					confid	0.00		N	N
N/A	Y01585	MMS	BPXA	100.0000000							11/30/2004	5522.28	12.500	N	N
N/A	Y01635	MMS	CPAI	78.0000000	APC	22.0000000					12/31/2006	5693.30	12.500	N	N
N/A	Y01636	MMS	CPAI	78.0000000	APC	22.0000000					12/31/2006	5693.30	12.500	N	N
N/A	Y01637	MMS	CPAI	78.0000000	APC	22.0000000					12/31/2006	5693.30	12.500	N	N
N/A	Y01638	MMS	CPAI	78.0000000	APC	22.0000000					12/31/2006	5576.75	12.500	N	N
N/A	Y01639	MMS	CPAI	78.0000000	APC	22.0000000					12/31/2006	5693.30	12.500	N	N
N/A	Y01640	MMS	CPAI	78.0000000	APC	22.0000000					12/31/2006	5693.30	12.500	N	N
N/A	Y01641	MMS	CPAI	100.0000000							12/31/2006	1068.59	12.500	N	N
N/A	Y01642	MMS	CPAI	100.0000000							12/31/2006	5310.88	12.500	N	N
N/A	Y01646	MMS	BPXA	100.0000000							11/30/2006	3338.62	12.500	N	N
N/A	Y01647	MMS	BPXA	100.0000000							11/30/2006	3628.94	12.500	N	N
N/A	Y01648	MMS	BPXA	100.0000000							09/30/2006	2600.69	12.500	N	N
N/A	Y01649	MMS	BPXA	100.0000000							09/30/2006	4802.70	12.500	N	N
N/A	Y01650	MMS	BPXA	100.0000000							09/30/2006	5307.81	12.500	N	N
N/A	Y01651	MMS	BPXA	100.0000000							09/30/2006	3.00	12.500	N	N
N/A	Y01661	MMS	CPAI	100.0000000							10/31/2006	3745.00	12.500	N	N
N/A	Y01667	MMS	CPCO	100.0000000							10/31/2008	3517.51	12.500	N	N
N/A	Y01668	MMS	CPCO	100.0000000							10/31/2008	3306.13	12.500	N	N
N/A	Y01669	MMS	CPCO	100.0000000							10/31/2008	2316.97	12.500	N	N
N/A	Y01670	MMS	CPCO	100.0000000							10/31/2008	2122.13	12.500	N	N
N/A	Y01671	MMS	CPCO	100.0000000							10/31/2008	4559.88	12.500	N	N
N/A	Y01672	MMS	CPCO	100.0000000							10/31/2008	3691.90	12.500	N	N
N/A	Y01673	MMS	BPXA	100.0000000							10/31/2008	1667.33	12.500	N	N
N/A	Y01674	MMS	CPCO	100.0000000							10/31/2008	950.00	12.500	N	N
N/A	Y01675	MMS	CPCO	100.0000000							10/31/2008	5635.29	12.500	N	N
N/A	Y01676	MMS	CPCO	100.0000000							10/31/2008	2536.31	12.500	N	N
N/A	Y01678	MMS	CPAI	50.0000000	CHEVRON	50.0000000					10/31/2008	267.00	12.500	N	N
N/A	Y01679	MMS	CPAI	50.0000000	CHEVRON	50.0000000					10/31/2008	5517.53	12.500	N	N
N/A	Y01680	MMS	CPCO	100.0000000							10/31/2008	4428.49	12.500	N	N
N/A	Y01681	MMS	CPCO	100.0000000							10/31/2008	4710.00	12.500	N	N
N/A	Y01682	MMS	CPCO	100.0000000							10/31/2008	5050.20	12.500	N	N
N/A	Y01683	MMS	CPCO	100.0000000							10/31/2008	156.00	12.500	N	N

LEGEND

APC	ANADARKO PETROLEUM COMPANY
BPAP	BP AMERICA PRODUCTION COMPANY
BPXA	BP EXPLORATION (ALASKA) INC.
CHEVRON	CHEVRON U.S.A. INC.
CPAI	CONOCOPHILLIPS ALASKA, INC.
CPCO	CONOCOPHILLIPS COMPANY
DEVON	DEVON ENERGY PRODUCTION COMPANY, L.P.
DOYON	DOYON LIMITED
EM	EXXON MOBIL CORPORATION
EM AK	EXXONMOBIL ALASKA PRODUCTION INC.
EM OIL	EXXONMOBIL OIL CORPORATION
ENCANA	ENCANA OIL AND GAS (USA) INC.
FOREST	FOREST OIL CORPORATION
LEEDE, ED	EDWARD H. LEEDE
MURPHY	MURPHY EXPLORATION (ALASKA), INC.
MURPHY AK	MURPHY EXPLORATION (ALASKA), INC.
NANA	NANA REGIONAL CORPORATION INC.
PAAI	PHILLIPS ALPINE ALASKA L.L.C.
PETRO-HUNT	PETRO-HUNT L. L. C.
UNOCAL	UNION OIL COMPANY OF CALIFORNIA
ALASKA	State of Alaska, Department of Natural Resources, Division of Oil and Gas
ASRC	Artic Slope Regional Corporation
BLM	Bureau of Land Management
MMS	Minerals Management Service

(1) Lessee of Record is EXXONMOBIL CORPORATION
(2) Lessee of Record is EXXONMOBIL OIL CORPORATION
(3) Lessee of Record is BP EXPLORATION (ALASKA) INC.

NOTE: Where a lease has been divided into segments in the Department of Natural Resources records, the ownership shown above is for only one segment.

Appendix A.8	North Slope Resource Estimate

Alaska North Slope Oil and Gas Reserves - DNR 2002 Report

North Slope

Unit or Area	Oil Reserves (MMBO)[1]	Gas Reserves (Bcf)[1]	Royalty Percent	Royalty Oil Reserves (MMBO)	Royalty Gas Reserves (Bcf)
Badami Unit	2	39	14.6%	0	6
Barrow					
East Barrow	-	5	0.0%	-	-
South Barrow	-	4	0.0%	-	-
Walakpa	-	25	0.0%	-	-
TOTAL Barrow	-	34		-	-
Colville River Unit					
Alpine	431	-	10.0%	43	-
CRU Satellite	120	-	12.5%	15	-
TOTAL CRU	551	60		58	60
Duck Island Unit	162	843	12.5-14.4%	20	121
Kuparuk River Unit					
Kuparuk	1,031	590	12.5%	129	74
West Sak[2]	343	-	12.5%	43	-
Tabasco	11	-	12.5%	1	-
Tarn	83	21	12.5%	10	3
Meltwater	33		12.5%	4	
Kuparuk Satellite	94	-	12.5%	12	-
TOTAL KRU	1,595	611		199	76
Milne Point Unit	503	14	14.6%	73	2
North Star	191	450	16.0%	31	72
Prudhoe Bay Unit					
Initial Participating Areas					
Prudhoe IPAs[2]	3,024	-	12.5%	378	-
PBU Satellites[3]	482	-	12.5%	60	-
TOTAL PBU IPA	3,506	23,000	12.5%	438	2,875
Greater Point McIntyre Area					
Lisburne	36	276	12.5%	5	35
Niakuk	44	26	12.5%	6	3
North Prudhoe Bay State	-	-	12.5%	-	-
Pt. McIntyre	154	577	13.8%	21	80
West Beach	-	-	12.5%	-	-
TOTAL GPMA	234	879		31	117
TOTAL PBU	3,741	23,879		470	2,992
Point Thomson	435				
Other Undeveloped[4]	174	8,000	12.5%	22	1,000
TOTAL North Slope (State Lands)	6,920	33,930		873	4,330

Notes:

[1] Remaining recoverable reserves are based on the sum of forecasted production from 2002 through 2034. MMBO = Million Barrels of Oil; Bcf = Billion Cubic Feet.

[2] Oil Rim and Gas Cap.

[3] Includes Midnight Sun, Aurora, Borealis, and Polaris.

[4] Includes Liberty and other known on- and off-shore accumulations.

Source: Alaska Department of Natural Resources and Department of Revenue.